BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	DOCKET NO. E-00000J-14-0023

At: Phoenix, Arizona

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COASH & COASH, INC.
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1802 N. 7th Street, Phoenix, AZ 85006
602-258-1440 staff@coashandcoash.com

ORIGINAL

By: Colette E. Ross, CR
Certified Reporter
Certificate No. 50658

Gary W. Hill, RMR
Certified Reporter
Certificate No. 50812

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BE IT REMEMBERED that the above-entitled and numbered matter came on regularly to be heard before the Arizona Corporation Commission, in Hearing Room 1 of said Commission, 1200 West Washington Street, Phoenix, Arizona, commencing at 9:06 a.m. on the 6th of May, 2016.

BEFORE: TEENA JIBILIAN, Assistant Chief Administrative Law Judge

Note: No roll call taken. The following is a list of the parties of record.

PARTIES OF RECORD:

For Arizona Public Service Company:

PINNACLE WEST CAPITAL CORPORATION
Law Department
By Mr. Thomas Loquvam
400 North Fifth Street
Phoenix, Arizona 85004

and

SNELL & WILMER, L.L.P.
By Mr. Raymond S. Heyman
400 East Van Buren
Phoenix, Arizona 85004

PARTIES OF RECORD:

For Tucson Electric Power Company and UNS Electric, Inc.:

SNELL & WILMER, L.L.P.
By Mr. Michael W. Patten
400 East Van Buren
Phoenix, Arizona 85004

and

UNS ELECTRIC, INC.
By Mr. Bradley S. Carroll
88 East Broadway Boulevard
Tucson, Arizona 85701

For The Alliance for Solar Choice:

ROSE LAW GROUP, P.C.
By Mr. Court S. Rich
7144 East Stetson Drive, Suite 300
Scottsdale, Arizona 85251

For Arizona Investment Council:

OSBORN MALEDON
By Ms. Meghan H. Grabel
2929 North Central Avenue, 21st Floor
Phoenix, Arizona 85012

For Western Resource Advocates, Vote Solar:

ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST
By Mr. Timothy Hogan
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004

PARTIES OF RECORD:

For Garkane Energy Cooperative, Inc.; Mohave Electric Cooperative, Inc.; and Navopache Electric Cooperative, Inc.:

LAW OFFICES OF WILLIAM P. SULLIVAN, P.L.L.C.
By Mr. William P. Sullivan
501 East Thomas Road
Phoenix, Arizona 85012

For Sulphur Springs Valley Electric Cooperative, Inc.:

CROCKETT LAW GROUP, P.L.L.C.
By Mr. Jeffrey W. Crockett
2198 East Camelback Road, Suite 305
Phoenix, Arizona 85016

For Arizona Solar Deployment Alliance:

LAW OFFICES OF GARRY D. HAYS, P.C.
By Mr. Garry D. Hays
2198 East Camelback Road, Suite 305
Phoenix, Arizona 85016

For Freeport Minerals Corporation and Arizonans for Electric Choice and Competition:

FENNEMORE CRAIG, P.C.
By Mr. C. Webb Crockett
2394 East Camelback Road, Suite 600
Phoenix, Arizona 85016

For Grand Canyon State Electric Cooperative Association, Inc.:

GALLAGHER & KENNEDY, P.A.
By Ms. Jennifer Cranston
2575 East Camelback Road
Phoenix, Arizona 85016

PARTIES OF RECORD:

For IBEW Locals 387, 1116 and 769:

LUBIN & ENOCH, P.C.
By Mr. Nicholas J. Enoch
349 North Fourth Avenue
Phoenix, Arizona 85003

For Arizona Competitive Power Alliance:

Mr. Greg Patterson, Of Counsel
MUNGER CHADWICK
916 West Adams, Suite 3
Phoenix, Arizona 85007

For Arizona Solar Energy Industries Association:

AriSEIA
Mr. Tom Harris
2122 West Lone Cactus Drive, Suite 2
Phoenix, Arizona 85027

For Patricia C. Ferre:

Patricia C. Ferre
In Propria Persona, via teleconference
P.O. Box 433
Payson, Arizona 85547

For Vote Solar:

EARTHJUSTICE
By Mr. Michael A. Hiatt
633 17th Street, Suite 1600
Denver, Colorado 80202

For the Residential Utility Consumer Office:

RUCO
By Mr. Daniel W. Pozefsky, Chief Counsel
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007

PARTIES OF RECORD:

For the Arizona Corporation Commission Staff:

Ms. Maureen A. Scott and Mr. Matthew Laudone,
Staff Attorneys
Legal Division
1200 West Washington Street
Phoenix, Arizona 85007

ACALJ JIBILIAN: Good morning, and welcome back, everyone, to the continuation of this proceeding. I am not going to take appearances today. I can see who is here.

So we will just go ahead and start with TASC's witness. Are you ready to call your witness, Mr. Rich?

MR. RICH: Yes, Your Honor. Thank you. Good morning. TASC calls R. Thomas Beach.

R. THOMAS BEACH,

called as a witness on behalf of TASC, having been first duly sworn by the Certified Reporter to speak the truth and nothing but the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. RICH:

Q. Great. Good morning, Mr. Beach.

A. Good morning.

Q. All right. You should have before you what have been marked as TASC Exhibits 26, 27, and 28. Do you see those up there?

A. Yes, I do.

Q. Okay. And can you identify each of those for us?

A. TASC-26 is my direct testimony in this docket. TASC-27 is my rebuttal testimony. And TASC-28 are some errata corrections to my 2, Exhibit 2 to my direct testimony.

Q. Okay, great. Let's start with Exhibit 26, your direct testimony. Was that prepared by you or at your direction?

A. Yes, it was.

Q. Okay. And if you were to be asked those same questions today under oath, would the responses be the same?

A. Yes, they would.

Q. Okay. And are there any other, you mentioned the errata that's contained in Exhibit 28, are there any other changes or corrections that you need to make to that today?

A. Yes. There is one minor correction in Exhibit 2 of my direct testimony, which is the benefit/cost study on APS that we conducted. Table 4 on page 12, there is a page reference that's missing. If you look in Table 4 in the line that's labeled capacity losses in the first column, and then the value is 11.7 percent, and the notes in the, and sources in the third column, it says SAIC study at and then there is a blank there, that should be page 2-9.

Q. Okay. And that's in Exhibit 2 to your direct testimony on page 12, correct?

A. Yes.

Q. All right. On the version that's in front of you, would you mind, I guess, let's just have you write in the correct, fill in that blank if you have a pen there.

A. Okay.

Q. Then you can just initial next to it. All right. And I will, we will move them all at once.

Let me ask you on Exhibit 27, your rebuttal testimony, was that prepared by you or at your direction?

A. Yes, it was.

Q. Okay. And do you have any changes to make to that document today?

A. No, I don't.

Q. All right. And would your answers to that, to those questions that were asked there be the same today under oath as they were when you submitted it?

A. Yes, they would.

Q. Okay. And finally, with regard to Exhibit 28, was that notice of errata filing done at your direction and do you agree with those changes that are made and reflected in that filing?

A. Yes, I do.

MR. RICH: Okay. Great.

Your Honor, I would move the admission of TASC-26, 27, and 28.

ACALJ JIBILIAN: Is there any objection?

(No response.)

ACALJ JIBILIAN: TASC-26, 27, and 28 are admitted.

(Exhibit TASC-26 through TASC-28 were admitted into evidence.)

BY MR. RICH:

Q. Okay. Great. Thank you.

So Mr. Beach, I am going to give you an opportunity to summarize your direct and rebuttal testimony and respond to some of what you heard from the stand. So if you would like to do that, please go ahead.

A. Yes. Thank you very much for the opportunity to appear today.

My testimony proposes a benefit/cost methodology for valuing DG resources that builds upon the widely used industry standard approach to assessing the cost effectiveness of other types of demand-side resources, such as energy efficiency and demand response. The primary reason to use a similar approach is so that all demand-side resources, distributed generation as well as energy efficiency and demand response, are evaluated on the same basis.

Importantly, this approach also evaluates demand-side resources in a manner similar to supply-side utility rate base additions. This approach considers the long-term benefits and costs of DG resources over their full expected life in the same way that other new resources are evaluated. These benefit/cost analyses assess the benefits and costs of DG from multiple perspectives, including, first, participating ratepayers who install DG, second, other nonparticipating ratepayers, and, third, the utility system and society as a whole.

The goal of the regulator should be to balance the interests of all of these stakeholders, who collectively constitute the public interest in the development of renewable DG technologies. In particular, demand-side resources depend on the decisions of customers to make long-term investments to reduce their energy use, shift their loads or produce their own generation. So it is critical to balance the interests of both participating and nonparticipating ratepayers and not to favor either side.

The utility witnesses have testified in this hearing that customer-sited DG should not be treated as a demand-side resource at all but that, instead, their own customers who install DG should be treated more like the owners of merchant generation facilities. They argue that the fact that DG has differences from energy efficiency or demand response resources mean that it cannot be treated like energy efficiency or demand response. This ignores that there is a wide variety of efficiency and demand resource product and services that differ from each other. For example, some reduce energy use, others reduce peak loads. And cost effectiveness evaluation can be tailored to the particular type of energy efficiency and demand response resource. And they can also be adapted for distributed generation.

Despite the differences in these other demand-side options, DG is the only one that the utilities argue must be evaluated differently. The utilities have tried to shift the focus from customers adopting DG to the companies who sell or finance DG products. This makes little sense and appears to be an attempt by the utilities to misdirect the Commission.

For example, Home Depot no doubt sells many energy efficient heat pumps as a result of the residential rate design in Arizona, but the utilities do not claim that Home Depot is profiting off the current rate design or raising rates for nonparticipating customers. Remember, it is the individual customers who are making the decisions to install those heat pumps, just like it is the individual solar customers who are installing DG.

The fact that nonutility customers compete to provide these products and services is a distraction raised by the utilities when the focus should be on the utility costs which can be reduced when customers choose all types of demand-side resources.

Distributed generation, like energy efficiency, is implemented on a customer's premises as a result of a customer's decision to deploy their own private capital and they pay the capital costs.

In sum, all demand-side resources, including DG should be judged using the well established methodology now used for energy efficiency and demand response.

Several of the utility parties have urged the Commission to use cost of service studies to assess the cost effectiveness of renewable DG. Cost of service studies are based on utility costs in only a single test year and thus fail to capture the full benefits and costs of renewable DG over the long-term life of these resources. A cost of service study is based on embedded costs, not on the utility's long-run marginal costs and, thus, is likely to underestimate the long-run costs avoided by renewable DG, particularly the avoided capacity costs for generation, transmission, and distribution.

Regulators do not use cost of service studies to judge the cost effectiveness of other types of resources and do not use them to judge the merits of utility owned resources. If a cost of service were used for the purpose of judging a utility owned resource, those resources often would fail because cost recovery through rate base is front loaded to the early years of a plant's life, and, thus, new utility owned resources often raise rates in the first rate case after they enter service even if they are cost effective on a lifecycle basis.

I would like to clear up some misconceptions about benefit/cost studies of renewable DG. The intent of these studies is not to set rates. It is to balance the benefits and costs of DG technologies. Obviously rates and rate design impact this balance because the primary costs of net metering for nonparticipating ratepayers are the lost revenues from running the meter backwards at the retail rate. These same lost revenues are the bill savings that are the primary benefit of DG for participating ratepayers.

So benefit/cost tests are not setting rates but you can affect the balance of benefits and costs for the two groups by making rate design changes. If the Commission concludes that rate design changes are necessary to adjust this balance in Arizona, the types of changes that the Commission should prioritize are, first, requiring the use of time-of-use rates that better reflect how utility costs vary through the day or, second, adopting minimum bills, which continue to allow the greatest scope for customers to exercise the choice to adopt DG.

Fixed charges should be avoided because they give the customer no economic signal to use energy wisely. And demand charges should also be avoided because a customer's highest 15-minute demand does not necessarily align with peak demands at either the circuit or system level. And demand charges are confusing to and poorly accepted by small customers.

The Commission should take care to design rates that are understandable and acceptable to customers, recognizing the future potential that customers who use DG and storage may be able to cut the cord with the utility system completely, which is an outcome that I think we all want to avoid.

Despite the urging of the utilities, DG

customers should not be placed into their own rate class. On this we firmly agree with Staff that it makes little sense to start down the road of creating separate customer classes for every new energy technology that customers adopt. Mr. Monsen has a detailed discussion of this issue in his testimony and he shows that other demand-side technologies also can produce significant changes in customers' load profiles as can DG. Basically DG makes a larger than average residential customer into a smaller than average one. But both before and after adding DG, their use is within the typical range for residential customers.

The parties to this case agree on many of the benefits and costs of renewable DG. Two of the benefits on which there is not agreement are fuel hedging and market price mitigation. On fuel hedging, it should be obvious that solar DG like other types of renewable generation displaces marginal use of natural gas to produce electricity and, thus, reduces the amount of natural gas burned by the utility, decreasing its volume of gas purchases that are subject to price volatility. That's how renewables provide a hedge, and the value of this hedge is not zero.

With respect to market price mitigation, what that means is simply that the increase in renewable generation in the western U.S. and Arizona with zero variable cost will reduce wholesale market prices in this region as it has in places like Germany that have high penetrations of renewables. You may be aware that in a few hours today the amount of renewable output in California depresses market prices to below zero to the benefit of utilities who are paid to take this power, utilities in Arizona, for example, who are paid to take this power. So any utility that purchases wholesale power or natural gas will benefit from the lower prices that result from renewable deployment.

With respect to the Seidman study of the economic impacts of renewable DG, this study is flawed as a result of the assumptions that APS provided for Arizona State. I understand that APS has indicated it is not submitting the report into evidence to prove the truth of the matters contained in the report, which is a good thing, because of these flaws. In terms of the flaws there are four major ones.

First, APS's scenarios assume that DG located at the point of end use would have no effect on its future investment in transmission and distribution infrastructure. However, most other parties to this proceeding recognize that avoided T&D is a benefit of distributed generation.

APS assigns, the second flaw, APS assigns a capacity value to solar that is far too low given the output of solar over the utility's peak hours. Furthermore, any decline in solar's capacity value with increasing penetration can be slowed or reversed with west-facing systems and a modest amount of storage.

APS's work papers show that the utility assumed that the federal investment tax credit is not extended when in fact it has been extended at the 30 percent level. This is the third flaw in the assumptions. As a result, additional solar investment in Arizona will benefit the state much more than the Seidman study has estimated because most of the costs will be borne by taxpayers in other states.

And fourth and finally, the Seidman study does not consider the broad economic benefits for the State of Arizona if businesses in Arizona leverage the state's leadership position in solar technologies, its abundant solar resources and its local expertise to serve markets to distributed renewable resources outside of Arizona. California now has more solar workers than utility employees. The reason for this is not just because the state has half a million DG installations but because the solar industry is serving solar markets in the rest of the U.S. and around the world.

APS's rebuttal criticizes our exemplary benefit/cost study for APS for looking at the entire output of DG facilities instead of just looking at DG exports. Let me be clear. We agree that the focus of the methodology adopted by this proceeding should be the value of exports, because DG customers have a right under PURPA to serve their own on-site loads with their own renewable DG systems and to export excess energy to the utility. However, as a technical matter of doing the calculations, valuing only the exports is more difficult because you need to do the analysis on an hourly basis, considering both the hourly DG output and hourly loads of the DG customer to determine when the exports occur.

We suggest that valuing the full output is an easier alternative. And the studies in California that have looked at the value of both exports alone and all output have not found a significant difference between the two. I will note that Mr. Snook's cost of service testimony valued all DG output as did the two prior DG solar cost effectiveness studies that APS has commissioned. So in the past, when APS has had to do these calculations, it has also looked at all output. So to be clear, we are not opposed to valuing just the exports, but the Commission should be aware that this will complicate the analysis probably for little benefit.

Finally, this case includes comparisons between the costs of utility scale and rooftop solar systems. Utility scale solar has lower capital costs as a result of economies of scale. However, despite the claims of a few parties in this proceeding, this is not a simple apples to apples comparison because the two types of solar do not provide the same product. Rooftop solar provides a retail product while utility scale solar provides a wholesale product.

The retail rooftop product has been delivered to load whereas the wholesale utility scale product has not. Thus, for a fair comparison between the two resources, at a minimum one must add to the cost of utility scale solar the marginal cost associated with delivering this power to the customers that can be served by solar DG located on their own roofs.

In addition, there is nothing in APS's 2014 IRP or its draft 2017 IRP which indicates that rooftop and utility scale solar are substitutes for each other. So, if APS installs less rooftop solar, it is not committing to installing more utility scale solar, or vice versa.

Mr. Snook's testimony assumes that exports from DG solar avoid APS's marginal fuel, which is natural gas. There is no renewable energy standard requirement which requires the substitution of utility scale to rooftop solar as APS is in compliance with the REST goals. And in any event, there is a set-aside for DG solar that utility scale solar cannot satisfy.

Rooftop solar provides additional benefits to the local environment and the local economy that utility scale solar does not, as is discussed in my APS benefit/cost study.

Finally, there are important policy reasons to treat rooftop solar equitably so consumers continue to have the freedom to exercise a competitive choice and to become more engaged in and reliant in providing for their energy needs.

Thank you.

MR. RICH: Great. Thank you, Mr. Beach.

I will tender Mr. Beach for cross-examination at this time.

ACALJ JIBILIAN: Thank you.

Mr. Hogan, do you have questions for this witness?

MR. HOGAN: I do not, no.

ACALJ JIBILIAN: Mr. Enoch.

CROSS-EXAMINATION

BY MR. ENOCH:

Q. Good morning, Mr. Beach.

A. Good morning.

Q. Can you take a look at your TASC Exhibit 26. What is the date of that?

A. February 25th.

Q. Okay. Can you turn to page 7. Question 10, you make the comment starting at line 30 -- can you read that sentence for me.

A. Even though the Public Utility Commission of Nevada has subsequently decided to phase in the new DG rates over a 12-year period, the elimination of net metering, and in particular the reduction in the export rate, has decimated the rooftop solar market in Nevada resulting in more than a thousand documented layoffs at solar companies.

Q. And in support of that proposition you cite to your own testimony down below that you filed in the docket of the Public Utility Commission of Nevada, correct?

A. Yes.

Q. Okay. Can we take a look at APS Exhibit 11.

MR. RICH: Does the witness have that? What is that?

MR. ENOCH: APS Exhibit 11 is the decision, modified final order from the Public Utility Commission of Nevada.

BY MR. ENOCH:

Q. Is that what you are looking at, Mr. Beach? Could you turn -- well, actually, the last page of this document, if you just flip it over, page 183, this is dated February 17th, 2016, correct?

A. Yes.

Q. Okay. Now, let's turn back a few pages to page 179, paragraph 404. Can you read that paragraph for me, Mr. Beach, paragraph 404.

A. The information and testimony presented by Staff regarding the employment figures for Nevada's solar industry indicates that the figures cannot be reasonably relied upon as an estimate of the number of solar jobs in Nevada or the number of jobs that could potentially be impacted by this order. Further, no corroborating information from other sources was identified. No party to this proceeding provided any material support for the notion that a change in the NEM rates and tariffs would result in the loss of nearly 6,000 solar jobs. TASC and SEIA's objections to providing information that would help confirm or refute the figures for rooftop solar jobs in Nevada are perplexing.

Q. Okay. Should I assume that you don't agree with that finding from the Nevada Public Utility Commission?

A. No. My recollection of what happened in that case is there was some debate earlier in the proceeding, there was a debate about how many solar jobs there are in the Nevada. And that's the reference to the 6,000 solar jobs that's at the top of page 180. But the job losses that I documented in my testimony on grandfathering, which is what I am referring to in my testimony here, about the thousand job losses, that was very well documented.

We had, you know, notices that have been sent to the State of Nevada. You have to notify the state when you do layoffs. And so I basically just tallied up all the layoff notices that had been provided to the State of Nevada about the thousand layoffs.

Q. And assumed that those were the result of the changes in the net metering?

A. They were.

Q. Well, how do you know that?

A. Well, they occurred shortly after the Commission issued its order.

Q. So it follows that that is the result, on that shorter notice --

A. I'm --

Q. -- for the -- let me finish the question.

You took the notices for the mass layoff and you assumed that that was a consequence of a regulatory change by the Public Utility Commission in Nevada, correct? That's an assumption?

A. It was more than an assumption because a lot of the solar companies also issued press releases saying that's why the layoffs were occurring.

Q. Okay. Whatever the case may be, you would agree that Public Utility Commission of Nevada found that whole line of inquiry to be unsubstantiated? I don't want to put words in their mouth, but in section 404, they didn't agree with you.

A. I think I have already explained that that was about another issue. That was about how many total solar jobs there were in Nevada to begin with.

Q. Does this Public Utility Commission -- this is an 183-page decision. To the best of your recollection, does it have anything in there where it adopts that portion of your testimony in Nevada?

A. I would have to look at it. I don't know.

Q. If I represented to you that I have read it and I didn't see anything along those lines, would you have any reason to disagree with me?

MR. RICH: Your Honor, I am going to object.

Mr. Beach's testimony is about the impact of the decision in Nevada, not about what is in the order that implemented the decision in Nevada. And I think that's an important distinction.

BY MR. ENOCH:

Q. I think the point I am trying to make is you have a decision that came down on the 17th of February and then, correct me, a few days later you then filed testimony here and you don't mention that? Or do I have the sequence wrong?

A. I will agree that I filed my testimony here after this order came out.

MR. ENOCH: Okay. I have nothing else. Thank you.

ACALJ JIBILIAN: Ms. Grabel.

MS. GRABEL: Thank you, Your Honor.

CROSS-EXAMINATION

BY MS. GRABEL:

Q. Good morning, Mr. Beach.

A. Good morning.

Q. The document that you have in front of you, is it dated February 25th, 2016 and has a signature by Court Rich on the bottom of it? Is that correct?

A. Yes.

Q. I just noticed, and for your information, you might want to correct it, I think it says filing direct testimony of B. Thomas Beach. And that is not your correct initials, correct?

A. That is an error, yes.

Q. You would correct it to R. Thomas Beach?

A. Yes.

Q. In your opening I believe that you mentioned that California has more solar employees because the solar industries are installing systems elsewhere in the country, is that correct?

A. Yes, many companies based in California do a lot of business elsewhere.

Q. So the industries that you were referring to are those that were based in California?

A. Yes.

Q. Would you agree with me that the distributed generation customer sells energy to the utility?

A. Yes.

Q. And the utility sells it to the end user?

A. Yes.

Q. Thank you.

Mr. Beach, you worked from 1981 through 1989 at the California power utilities commission, is that right?

A. It is the Public Utilities --
Q. Public Utility.
A. -- Commission.
Q. Thank you.
And from there you established a private consulting practice with Crossborder Energy, correct?
A. Yes.
Q. You held no other jobs between your position on the CPUC and your current consulting practice Crossborder, is that right?
A. That's correct.
Q. And Crossborder Energy is based in Berkeley, California?
A. Yes.
Q. You mentioned in your testimony that you have actively participated in most of the major energy policy debates in California, including renewable energy development, is that right?
A. Yes.
Q. In fact, I looked at your CV. It identifies 84 matters on which you testified in California compared to a total of 16 matters about which you have testified elsewhere. Does that sound about right?
A. Well, I don't update my CV -- I update it about once a year. And recently I have been testifying

outside of California much more than I have inside of California. So it is -- that's right. I have testified in California more than I have in other states, but I have been traveling a lot recently.

Q. Do you think you traveled enough to add 60 more matters outside of California to your resumé?

A. Not 16, but --

Q. 60, I said.

A. No.

Q. Have you ever worked for a utility?

A. Yes.

Q. Directly for a utility?

A. You mean as an employee?

Q. Yes.

A. No. I have consulted for a number of utilities, though.

Q. Have you ever consulted for any investor-owned utilities?

A. Yes.

Q. Which utilities?

A. Pacific Gas & Electric.

Q. In what matter?

A. If you look at my CV, it is the first time I filed testimony as a private consultant. I was testifying on behalf of PG&E and its FERC regulated interstate pipeline affiliate.

Q. And what year was that?

A. That was, I think it was 1989.

Q. Have you testified for a public utility after 1989?

A. No, I have not.

Q. Have you ever worked for a utility in utility system operations?

A. No.

Q. You never worked in a utility system planning department?

A. No.

Q. Do you own a home in California?

A. Yes.

Q. Totally out of curiosity, do you have solar panels?

A. I have had solar panels since 2003.

Q. You have testified before for the Solar Alliance, is that correct?

A. Yes.

Q. And the Solar Energy Industries Association?

A. Yes.

Q. You have testified for Vote Solar?

A. Yes.

Q. And you are testifying today on behalf of The

Alliance for Solar Choice, correct?
A. That's correct.
Q. And you have done work previously for TASC, correct?
A. Yes.
Q. How much of your work in the past five years has been commissioned by solar advocacy groups?
A. In the last five years, I, you know, I don't know the exact amount, but I would say maybe 30 percent.
Q. I would like to show you AIC Exhibit No. 8. I believe you have all the AIC exhibits in front of you.
And, Your Honor, I gave you some as well over by that water jug again.
A. Okay.
MS. GRABEL: One second.
(Brief pause.)
BY MS. GRABEL:
Q. Would you please turn to page 2 of AIC Exhibit 8.
A. All right.
Q. This article announces the formation of The Alliance for Solar Choice and it appeared on the American Solar Energy Society website on May 13th, 2013. Do you see that?
A. Yes.

Q. If you would look at page 2, the third sentence below the paragraph, I mean below the photograph, I am sorry, what solar companies are listed as the founding members of The Alliance for Solar Choice? You see they are identified in red.

A. SolarCity, Sungevity, Sunrun, and Verengo.

Q. Thank you.

I would now like to turn to AIC Exhibit 9.

A. All right.

Q. Hold on. I have got to give them to everybody else.

(Brief pause.)

BY MS. GRABEL:

Q. AIC Exhibit 9, as you will see, is a copy of the intervention of The Alliance for Solar Choice for leave to intervene in the Tucson Electric Power rate case. Do you see that?

A. Yes.

Q. The Alliance for Solar Choice did not intervene recently in this docket. This is the most recent intervention request dated March 3rd, 2016.

Would you please read for me the companies that TASC lists as its member companies on this document. You will find them in paragraph 2?

A. Demeter Power Group, Geostellar Inc., LGCY

Power, REPOWER by Solar Universe, Sunrun Inc., and Sun Time Energy.

Q. Would you agree that of the original founding members of TASC that we looked at on AIC Exhibit 8 only Sunrun remains as a listed member according to TASC's most recent intervention request?

MR. RICH: Your Honor, Mr. Beach is not a direct employee of TASC. And I am not sure he has personal knowledge with regard to who are members and who are not.

MS. GRABEL: Mr. Rich, I am asking him to opine based on documents that TASC filed. And you haven't put any employee of TASC on the stand, so I have no other opportunity to ask a question of TASC.

ACALJ JIBILIAN: Overruled.

MR. RICH: Your Honor, just for the record, the members of TASC for the purposes of this docket were listed on our intervention request in this docket, just for the purposes of the record.

MS. GRABEL: TASC does not have a recent intervention request in this docket, Your Honor. The intervention request filed in this docket was based on 2014, I believe.

ACALJ JIBILIAN: Mr. Rich, are you saying that in this docket you are not representing the current members of TASC?

MR. RICH: No, Your Honor. I am just suggesting that --

ACALJ JIBILIAN: Okay. I overruled the objection, and he may answer the question.

MR. RICH: Okay. Thank you.

THE WITNESS: Well, the only name that's common to both lists is Sunrun.

BY MS. GRABEL:

Q. Thank you, Mr. Beach.

I would now like to show you AIC Exhibit 10. Give me a moment to pass it out.

(Brief pause.)

BY MS. GRABEL:

Q. Do you have it, Mr. Beach?

A. I do.

Q. Would you please turn to page 8 of 12. This document is a printout from Sunrun's website entitled Get the FAQs, Then Relax. On page 8 of 12 you see under Sunrun certified partners -- actually, I would like to look just above, starting where it says I heard about Sunrun through another solar company, how does Sunrun work with partners. Do you see that, Mr. Beach, in the middle of the page?

A. Yes, I do.

Q. The second paragraph below that says:

Partnership is one of those terms that's easy to throw around. But at Sunrun, it really means something. Our nationwide network of certified partners are the bedrock of our business because they allow us to provide stellar Sunrun service where you live.

Did I read that correctly?

A. Yes.

Q. This document then goes on for quite a few pages to identify Sunrun certified partners, is that right?

A. Apparently so, yes.

Q. Will you please turn to page 9 of this document.

A. Okay.

Q. Do you see that LGCY Power is listed as a certified partner of Sunrun?

A. Yes.

Q. Further down on the page do you see that Solar Universe is listed as a certified partner of Sunrun?

A. Yes.

Q. If you would turn to page 10 on this document, AIC Exhibit 10, do you see that Sun Time Energy is listed as a certified partner of Sunrun?

A. Yes.

Q. I would now like to show you, if you turn to AIC Exhibit 11. Again give me a moment to hand it out to everybody else.

(Brief pause.)

BY MS. GRABEL:

Q. Do you have AIC-11 in front of you, Mr. Beach?

A. Yes.

Q. AIC-11 is a printout from the Demeter Power Group website. Do you see that reflected on the top left-hand corner on page 11?

A. Yes.

Q. AIC-11 rather.

According to the Demeter Power website, it offers services that are available in the open market commercial PACE markets, is that correct, under current markets?

A. Yes. The type is rather small, but that's what it says.

Q. Microscopic, my apologies.

Can you tell whether or not there has been PACE legislation enacted in Arizona from looking at this map?

A. This map appears to indicate that there has not been PACE legislation in Arizona.

Q. Thank you.

It is therefore unlikely that Demeter Power does business in Arizona, is that correct?

A. You know, I, I mean PACE is just one form of solar financing. So I have no idea whether Demeter might offer other kinds of solar financing in other markets in Arizona as well.

Q. If I represented to you that Demeter Power's website suggests it does not offer any form of financing other than PACE financing, subject to check, would you agree with that?

A. Subject to check.

Q. Thank you.

I would now like you to look at AIC Exhibit 12. And this one killed a lot of trees so it is going to take me a minute to hand out.

(Brief pause.)

BY MS. GRABEL:

Q. AIC Exhibit 12 is a copy of Sunrun Inc.'s Form 10-K for the fiscal year December 31st, 2015. Do you see that?

A. Yes.

Q. Would you please turn to page 21 of 270 of this document.

A. Okay.

Q. Look at the heading on the second paragraph up from the bottom. It notes that Sunrun's business is concentrated in certain markets putting us at risk of region specific disruptions. Do you see that?

A. Yes.

Q. Will you please read the first sentence that follows, beginning as of December 31st, 2014 -- 2015.

MR. RICH: I am sorry. May I inquire through Ms. Grabel. Where are you?

MS. GRABEL: Sure. If you look at page 21 of 270, it is the page number noted on the top right-hand of the document.

MR. RICH: I got it now. Thank you.

MS. GRABEL: Okay. Sure.

BY MS. GRABEL:

Q. And I am starting with the as of December 31st, 2015. My apologies.

A. As of December 31st, 2015, the majority of our customers were in California.

Q. Would you agree that Sunrun's primary market is in California, not Arizona?

A. Well, that's what this says. And it wouldn't surprise me given that California has, by a significant margin, the largest number of solar customers of any state in the country.

Q. Thank you.

I would now like you to take a look at AIC Exhibit 13.

(Brief pause.)

BY MS. GRABEL:
Q. Do you have it in front of you?
A. Yes.
Q. AIC Exhibit 13 is a fact sheet published on April 7th, 2016 by the Solar Energy Industries Association. Do you see that?
A. I think it says April 7th. I am not sure that's the date you just said.
Q. April 7th, correct.
A. Okay.
Q. Would you please look at the first bullet under at a glance.
A. Yes.
Q. If you want to take a minute to read that paragraph...
A. Okay.
Q. Would you agree that, according to SEIA, Arizona has 197 solar contractor installer companies?
A. That's what it says, yes.
Q. Thank you.
Would you agree that TASC membership does not comprise the majority of rooftop solar companies that do business in Arizona?
A. Certainly by number I would agree with that, yes.

Q. Thank you.
I would now like you to turn to AIC Exhibit 14.
(Brief pause.)
BY MS. GRABEL:
Q. Do you have AIC-14 in front of you?
A. Yes.
Q. AIC Exhibit 14 is a list of the subsidiaries of SolarCity Corporation as of February 10th, 2016. It is filed as an exhibit to SolarCity's annual SEC disclosure filing. Will you please turn to page 7 of this document.
A. Okay.
Q. Read the first T. It goes alphabetically. The Alliance for Solar Choice, LLC is actually a subsidiary of SolarCity, is that correct?
A. That's what this says.
Q. Do you believe that SolarCity would make a false representation on its corporate disclosure filing?
A. No, I have no reason to think that this is inaccurate.
Q. Do you know whether, as TASC's parent company, SolarCity is required to approve TASC's activities?
A. You know, in my experience of consulting for TASC, SolarCity has certainly been actively involved in TASC's activities.

Q. Is SolarCity paying you for your testimony today?
A. In this case I believe they are, yes.
MR. RICH: Your Honor, if I can just briefly clarify, and I did this with Ms. Grabel in the last proceeding, this proceeding began before SolarCity withdrew from TASC. And for the purposes of this proceeding, they are a member of TASC. I just clarify that, as I have done previously for Ms. Grabel.
MS. GRABEL: And, Mr. Rich, the list of subsidiaries of SolarCity Corporation was filed as of February 10th, 2016, which would be after TASC may have withdrawn -- I mean SolarCity may have withdrawn from its membership. But it is still listed as a subsidiary in its corporate disclosure, correct?
MR. RICH: I am not going to be cross-examined here. But I wanted to confirm for the record that it is our -- that SolarCity is a member of TASC for the purposes of this docket.
ACALJ JIBILIAN: We can save the rest of any discussion on this for the briefings.
BY MS. GRABEL:
Q. Did you speak with representatives from SolarCity about your testimony today?
A. Yes.

Q. Who did you speak with?
A. My recollections are that the SolarCity people who have been involved in this, Thad Kurowski and Eliah Gilfenbaum I think reviewed my testimony. They both work for SolarCity.
Q. Did you speak with anyone else at SolarCity?
A. I think that's probably it.
Q. Have you spoken with any of their executives? And by "their," I mean SolarCity's executives.
A. I am not sure what, how to define executive.
Q. Have you spoken with their president?
A. No, not about this matter.
Q. Have you spoken with him about other matters?
A. Yes.
Q. Have you spoken with him about other matters regarding proceedings in Arizona?
A. No.
Q. Did you speak with any employee of Sunrun for your participation in this docket?
A. Yes.
Q. Who from Sunrun did you speak with?
A. Kim Sanders.
Q. Who is Kim Sanders?
A. She is an employee of Sunrun who does regulatory work for Sunrun.

Q. I would like to turn now to your direct testimony, Mr. Beach. If you would turn to page 3 of your direct testimony, you testify that there is a, quote, developing consensus for using cost effectiveness tests developed for EE and DR programs to analyze the cost effectiveness of solar PV systems, is that right?
A. Yes.
Q. Specifically you state on line 27 that, quote, this suite of cost effectiveness tests is now being adapted to analyses of NEM and demand-side DG more broadly as state commissions recognize that evaluating the costs and benefits of all demand-side resources -- EE, DR, and DG -- using the same cost effectiveness framework will help ensure that all of these resource options are evaluated in a fair and consistent manner.
Did I read that correctly?
A. Yes.
Q. You would agree that the EE and DR tests to which are referred in this sentence are screening tools, correct?
A. Yeah, I wouldn't disagree with that characterization.
Q. They are not used to establish the amount that ratepayers would pay for the EE and DR programs, correct?

A. That's correct. And I think in my introduction I -- that's consistent with my discussion that this methodology is not about setting rates.

Q. Well, that actually confused me a little bit, your introduction, because you say the methodology is not about setting rates, but then you go on to say that rates should be adapted to reflect the results of the value of solar analysis.

So how exactly would you use the output of the value of solar formula?

A. Well, you know, for example, let's say that you do your evaluation and it looks like, you know, let's just say that it looks like nonparticipating ratepayers are getting a benefit, but participating ratepayers, that solar is tough to make it cost effective in a particular market. Well, in that case, the solution might be for the state to implement an incentive program to provide an incentive that's paid for out of utility rates to customers who adopt solar. And so in that case, that would restore the balance between participating and nonparticipating ratepayers. That's one example.

Another example would be if you felt like there was a burden on nonparticipating ratepayers from solar DG, so that maybe the RIM test came out, you know, significantly less than one, and you wanted to restore that balance and maybe participating ratepayers were getting, their bill savings were substantially greater than their costs, well, in that case, perhaps you would want to implement a minimum bill or require solar customers to be on time-of-use rates so that it could reduce the lost revenues to the utility and reduce the bill savings to the solar customer and thereby restore the balance. It could work both ways.

Q. Assume that the Commission were to find both that DG does benefit nonparticipating ratepayers but also that there is a cost shift between DG customers and non-DG customers because of the allocation of fixed costs in the rate design. Is there a way to incentivize the solar market and still fix the cost shift issue?

A. You just said that DG benefits nonparticipating ratepayers.

Q. Correct.

A. Then there wouldn't be a cost shift.

Q. Why?

A. Well, the cost shift would be the opposite direction. The cost shift would be from participating ratepayers to nonparticipating ratepayers because the nonparticipants are benefiting. You have it backwards.

Q. Well, I suppose that depends on your definition of costs and benefits. One is monetary. The other could be something a little bit more subjective, correct?

A. You know, it -- certainly there are some benefits that are more, you know, I don't want to call them subjective, but that are not direct benefits, you know, that are more externalities or societal benefits. And, yes, those can be considered by the regulator in setting that balance.

Q. And do you recommend that the Commission consider externalities and other indirect benefits as part of your value of solar analysis?

A. Yes. I think you should try to quantify those externalities to the extent you can. And they shouldn't be used directly to change rates or provide incentives, but they certainly should be considered by the regulator in their deliberations.

Q. As evidence of the developing consensus, as you stated in your testimony, that you should use the cost effectiveness programs associated with EE and DR, you cite to the California PUC, the Mississippi PUC, and the Neveda PUC, correct?

A. Those are examples of commissions that have used this approach, yes.

Q. Do you have any other examples that evidence the developing consensus?

A. Certainly South Carolina has looked at this kind of balance.

Q. Has South Carolina done anything with respect to its DR, I am sorry, DG programs as a result of the cost effectiveness test associated with DR and EE?

A. Well, you know, South Carolina, it ended up being the commission conducted a proceeding and the parties settled that proceeding, the result of which was to establish a net metering and a DG program in South Carolina.

So they never really got to the stage of actually, you know, conducting the study because everybody reached a meeting of the minds.

Q. And isn't it true in California as well that, while they might have done a cost effectiveness analysis using EE and DR tests for DG, they never actually took any action based on that cost effectiveness analysis?

A. Well, they definitely took action to extend net metering in California. The order is a little vague on exactly what influence the analysis had. They didn't adopt a particular set of results from the public tool analyses that parties submitted because they feel that those analyses need further refinement. So I would say in California it is, it is not exactly clear from the commission's order the extent to which they considered those analyses.

Q. On page 8 of your direct testimony, Mr. Beach, line 21, you actually say the CPUC order does not rely on the public tool analyses, do you not?

A. Yes, yes.

Q. Isn't it also the case that Nevada has recently found net metering presented a significant cost shift to customers that did not participate in solar DG?

A. Yes. And I discuss that in my testimony. And that was largely based on a cost of service study. In my opinion, they also should have considered the net metering study that they conducted in 2014 that basically found a reasonable balance between benefit and costs of net metering in Nevada.

Q. I would like to direct you to the same lines you discussed with Mr. Enoch on page 7 of your testimony, starting on line, let's see, 31. Are you there?

A. Yes.

Q. You state with respect to the Nevada decision that, quote, the elimination of NEM and, in particular, the reduction of the export rate, in the export rate rather, has decimated the rooftop solar market in Nevada, resulting in more than 1,000 documented layoffs at solar companies. Did I read that correctly?

A. Yes.

Q. Is it your understanding that the rooftop solar market continued to try to market their product and couldn't or that they withdrew from the market because of the change?

A. Well, some companies have withdrawn from the market in Nevada. You know, as in Arizona, there are lots of solar companies in Nevada. I assume that some of them are maybe continuing to try to market their systems, but my understanding is it is very difficult now after the --

Q. Well, let's look at the --

A. -- CPUC decision.

Q. -- Sunrun, the member company of the organization that you are testifying on behalf of today. If you would, go back to AIC-12, Sunrun's 10K filing, and look at page 14 of 270. Are you there?

A. Yes.

Q. Will you please read the last sentence of the second paragraph under the heading electric utility statutes and regulations, electric utility statutes and regulations and changes to statutes or regulations may present technical, regulatory, and economic barriers to the purchase and use of our solar service offerings that may significantly reduce demand for such offerings.

What is the very last sentence of that section?
A. For example, we recently ceased operations in Nevada as a result of the elimination of net metering.
Q. Sunrun's 10-K disclosure indicates that its market exit was intentional. Would you agree?
A. In other words, that they made an affirmative decision?
Q. To exit the market, correct.
A. Yes.
Q. I would like you now to take a look at AIC-15.
(Brief pause.)
BY MS. GRABEL:
Q. Do you have it in front of you, Mr. Beach?
A. I do.
Q. Would you turn to page 15 of this document, which, for the record, is a presentation given by Sunrun for its 2015 Q4 review, dated March 10th, 2016. Do you see that?
A. Page 15, is that --
Q. Correct.
A. Yes, I am there.
Q. This is giving guidance and talking about its 2016 deployments. Do you see that?
A. Yes.
Q. Look at the first bullet under MW, megawatts.

Here Sunrun notes that it projects deploying 56 megawatts in Q1, excluding about 12 megawatts of Nevada backlog not built due to market exit. Do you see that?

A. Yes.

Q. Would you agree that Sunrun not only ceased operations in the Nevada market but it abandoned 12 megawatts of executed net metering contracts when it exited the market?

A. You know, I have no idea whether those were, those had signed -- you know, exactly what stage of development that 12 megawatts was in. And my guess is that it, if they had a contract with the customer, that a lot of that would have a mutual agreement between the customer and Sunrun to not go forward with the projects because they really were not meeting the customer's economic expectations any longer.

Q. Due to market exit. We have just established that the market exit was intentionally, correct?

A. No, due to the change in net metering regulations and rates in Nevada.

Q. Except that's not what this document says, does it, Mr. Beach? It says it excludes 12 megawatts of Nevada backlog not built due to market exit. Do you see that?

A. Yes. But Sunrun exited the energy efficiency market because of the Nevada PUC's decision to change net metering and to change the rate structure in Nevada. And, you know, there is plenty of documentation that the customers who had signed up for solar expecting to get a different deal were not happy and were seeking a way out of their contracts once the rates and the regulations changed.

Q. On page 15 of your direct testimony, Mr. Beach, you testify that a net metering customer that uses the grid but pays a small, zero, or even negative bill still pays fully for his use of the utility system, correct?

A. Yes.

Q. And this is because, you say, the customer has received credits for excess generation exported to the grid, correct?

A. Yes. In terms of the exports, it is the customer who is providing a service to the utility by providing power to the utility. So the customer is compensated by the utility for those exports.

Q. On line 14 of your testimony, you say that, quote, these credits are not the result of the solar customer's use of the utility system, unquote, is that correct?

A. Yes.

Q. Isn't it true that the solar customer uses the utility system to export power to the grid?

A. Well, obviously the power is being exported to the grid, but the utility takes title to the power at the meter. So once the power passes the meter, it is the utility's power. And it is the utility that is using their system to deliver that power to the neighbors.

Q. And --

A. So it is not, it is not the solar customer that's using the system, no.

Q. When the utility takes title to the power, when conveyed by the customer, that's a wholesale transaction, is it not?

A. You know, I don't think that it is considered, if you are looking for -- it is not considered, for example, by the FERC to be a wholesale transaction, but the power is the utility's once it goes out to the utility system.

Q. The utility is not the end user of the power, correct?

A. No. The utility delivers the power to the neighbors and gets compensated at the full retail rate for providing that service to the neighbors.

Q. Same page, page 14 of your direct testimony, on line 19 you say, quote --

A. I'm sorry. You said same page. We were on page 15. We were on page 15. Are we now on page 14?

Q. I am sorry. Yes, we are on page 15. You are correct. I am sorry, page 15, line 19.

A. Okay.

Q. Are you there?

A. Yes.

Q. You say that, quote:

There is the public policy issue of whether the bill credits for exported power at the retail rate are the right credit for these exports, and this case focuses on the methodology for analyzing that issue, but this does not change the fact that the solar customer has paid fully for his or her actual use of the utility system.

Did I read that correctly?

A. With the exception of changing this to a that, you read it correctly.

Q. Fair enough.

Would you agree that the bill credits for exported energy depend upon the net metering customer's rate structure?

A. Yes.

Q. Do you know that APS has a residential demand rate?

A. Yes, they do.
Q. Do you know that solar customers are participating on that rate?
A. There are a few. It is a relatively small portion of their solar population.
Q. Do you know that there are more than a thousand solar customers that are participating on that demand rate?
A. I am not sure I have seen the number of customers on that rate.
Q. So a solar customer who is on APS's three-part demand rate will receive less of a credit for his exported energy product than a solar customer who is on APS's two-part energy rate, is that correct?
A. That's likely.
Q. Is there any circumstance in which that wouldn't be true?
A. Well, the customer also pays a demand charge. And it is possible, but the customer could reduce their demand and get credit for that. But in general, I would agree with you, that the bill savings for the customer will be less under a demand based rate than under a rate that relies on volumetric rates.
Q. But it is possible for a solar customer to reduce their demand in response to a three-part demand

rate?

A. It is not easy but it is possible, yes.

Q. So the difference in compensation results from the amount of fixed utility costs that are included in the energy charge, correct?

A. Can you repeat that question.

Q. Sure. The difference in compensation that a DG customer receives if one is on a three-part demand rate versus a two-part volumetric rate is based on the amount of fixed costs that are included in the energy charge, is that correct?

A. Well, first of all, you know, I am not sure that I necessarily agree that -- you know, fixed costs are a matter of perspective. In the short run the utility's costs are fixed. But in the long run there are very few costs that the utility has that are fixed. So just I will put that out there as a bit of a disagreement with your use of the word fixed costs.

Generally I would agree that it is, as I said, it is easier for a solar customer to realize bill savings under an all volumetric rate than it is under a rate with a demand charge structure.

Q. Is it your contention that both of these solar customers, one on a three-part rate and one on a two-part volumetric rate, have both fully paid for his or her use of the system even though one has paid more than the other?

A. Yeah. My point that they both pay fully for their use of the system has to do with the fact that they pay, whenever the meter rolls forward, when power -- when they take service from the utility, when power flows from the utility grid to the customer, the customer pays fully for that use of the utility grid at the retail rate. When the meter runs backwards and the customer is exporting to the grid, they are providing service to the utility and they are not using the utility's system.

Q. So the compensation is based purely because of there is a net metering structure in place and not on the dollar amount that's attached to the net metering structure, is that your testimony?

A. Well, under different rate designs, customers will be compensated differently under net metering. Because under net metering your exports are compensated at whatever retail rate you are on. And so if the, if you -- two customers can be on different retail rates and will be compensated differently under net metering because of the different rate structure.

Q. And that's okay, that fully compensates them regardless what the actual credit to the customer is?

A. Well, you know, it is the customer's choice of, you know, of what rate they are on. The demand based rate in Arizona, my understanding is it is an optional rate. You are not required to be on it. So for whatever reason the solar customers who are on the demand based rate, they apparently looked at the economics of that and decided that that was an acceptable deal for them. Perhaps they are able to reduce their demand charges. But, again, it is an optional rate. If they want to be on the all volumetric rate, I don't know of any reason why they couldn't switch to the all volumetric rate. But apparently they decided that their best deal is on the demand based rate.

Q. You suggest that the benefits and cost analysis, that methodology you would use in this proceeding, be conducted over a 30, 20 to 30 long term, is that correct, 20 to 30-year long term?

A. Yes.

Q. I don't think I said that very well. Over a long 20 to 30-year term, I think I like that better. Correct?

A. Yes.

Q. Are you aware that the majority of customers who have installed rooftop solar in Arizona have leased the system from a solar company?

A. That would not surprise me.

Q. Would you agree that a solar customer who signs a 20-year solar lease might determine at some point during the lease term to terminate its contract?

A. That's possible. And there are, you know, there are provisions in those contracts for, you know, what happens in that event.

Q. Go back to AIC Exhibit 12, the Sunrun 10-K. I would like to turn your attention to page 31 of 270. Let me know when you are there.

A. Okay.

Q. If you could go to the very last section of this page, 31 of 270, under the topping we are exposed to the credit risk of homeowners and payment delinquencies on our accounts receivable, do you see that?

A. Yes.

Q. Will you please read the first three sentences of this paragraph.

A. Our customer agreements are typically for 20 years and require the homeowner to make monthly payments to us. Accordingly, we are subject to the credit risk of homeowners. As of December 31st, 2015, the average FICA score of customers under a lease or power purchase agreement was approximately 760, but this may decline to the extent FICA score requirements under future investment funds are relaxed.

Q. Please continue to the next sentence.

A. While to date homeowner defaults have been immaterial, we expect that the risk of homeowner defaults may increase as we grow our business.

Q. Would you agree that Sunrun believes there is a risk that a customer who signs a 20-year lease may decide to default on its contract?

A. Yes.

Q. Might a customer who signs a 20-year solar lease at some point sell the home to a buyer who does not want or cannot assume the solar lease?

A. That's possible. That might be something that gets resolved in the sale of the home I would think.

Q. In that case the solar unit on that home would be removed and would no longer generate electricity, is that correct?

A. Possible. I think some solar agreements also would allow the original owner of the system to take it with them if they are moving to a house that could, you know, accommodate that system.

Q. In such a case the solar unit would go on a different feeder, is that correct?

A. Possibly.

MR. RICH: Your Honor, I am not sure how much we are going down this road, but Mr. Beach did not testify about solar lease agreements or what happens when people sell their homes, and certainly is not here as an employee of an entity that does that.

MS. GRABEL: Thank you, Mr. --

MR. RICH: If we are done with that, that's fine. But I would object to further questions about lease contracts.

MS. GRABEL: Mr. Beach did offer testimony about taking a look at the value of solar over a 20 to 30-year term. And I am entering into evidence circumstances in which a DG unit will not be performing over a 20 to 30-year term, Your Honor.

ACALJ JIBILIAN: I don't think there is a question pending, is there?

MR. RICH: I think I was a little slow on that, Your Honor.

ACALJ JIBILIAN: Okay.

BY MS. GRABEL:

Q. Might a customer, Mr. Beach, who signs a 20-year solar lease one day buy an electric vehicle which would change the amount of energy he delivers to the utility?

A. Yes, that's possible. If a customer's consumption increases, you know, unless he adds more solar panels, the customer will pay for that increased consumption to the utility. So it is not like you can expand your solar panels for free.

Q. You would agree, would you not, that events such as lease terminations and purchasing an electric vehicle would change the levelized value of that customer's system, correct?

A. No, I wouldn't agree with that.

Q. You would not agree with that?

A. No.

Q. Thank you.

A. A customer --

Q. I have no further question. Thank you.

On pages 20 and 21 of your direct testimony you list several benefits and relatively few costs that should be considered as part of the value of solar analysis, including a societal benefits category for the societal tests, is that right?

A. Yes, I list benefits and costs on those pages.

Q. And one of those is a societal benefits category for the societal test that you think the Commission should undertake, is that correct?

A. Yes.

Q. I would like to ask you about other potential items that could be included on such a list. If you would go back to AIC Exhibit 12, the Sunrun 10-K, please turn to page 23 of 270. I am looking specifically at the, under the heading as the primary entity that contracts with homeowners, we are subject to risks associated with construction, cost overruns, delays, regulatory compliance, and other contingencies, any of which could have a materially adverse effect on business and results of operations.

Do you see that?

A. Yes.

Q. Will you please read the second and third sentence under that heading starting with we may be liable.

A. We may be liable either directly or through our solar partners to homeowners for any damage we cause to them, their home, belongings, or property during the installation of our systems. For example, we either directly or through our solar partners frequently penetrate homeowners' roofs during the installation process and may incur liability for the failure to adequately weatherproof such penetrations following the completion of construction.

Q. Should damage caused by the frequent penetration of homeowners' roofs be included as part of the cost of solar distributed generation?

A. You know, I -- that would seem to be something that a solar company would be liable for in the ordinary cost of business. So it is not something that -- it might affect a solar company if they have got substandard installation processes, but it is not going to affect other, shouldn't affect other ratepayers.

Q. Could you please turn to page 25 of 270. Here I am looking at the, under the section product liability, claims against us could result in adverse publicity and potentially significant monetary damages. Do you see that?

A. Yes.

Q. Will you please read the second sentence under that heading.

A. Because solar energy systems and many of our other current and anticipated products are electricity producing devices, it is possible that consumers or their property could be injured or damaged by our products, whether by product malfunctions, defects, improper installation, or other causes.

Q. Should potential damage to property or injury to person caused by rooftop DG products be considered a cost of solar in the Commission's value of solar analysis?

A. No. Again, I think that's a risk to the solar company itself. If there were shoddy installation that resulted in large claims against a solar company, the likely result of that would be that that company might go out of business. But I don't see that that would have a material impact on other ratepayers.

Q. If that company went out of business, would that have a material impact on the jobs that that solar company was able to provide?

A. Well, as I think we have established, there are a lot of solar companies. So if, you know, if one particularly poorly performing solar company went out of business, you know, I would assume that the workers who weren't incompetent might be able to get hired elsewhere.

Q. Please take a look at AIC Exhibit 16.

(Brief pause.)

BY MS. GRABEL:

Q. Do you have AIC-16 in front of you, Mr. Beach?

A. Yes.

Q. This is an article that appeared in Home Power Magazine entitled PV Safety and Firefighting. Do you see that?

A. Yes.

Q. Will you please read the first paragraph highlighted in gold.

A. Fire safety is typically the last thing people think of when planning their rooftop solar electric system, but it quickly becomes a hot topic when a blaze ignites. Here's a look into the potential hazards of PV systems when a fire breaks out and how to minimize risks to firefighters.

Q. And look at paragraph 3 of this article, starting with the presence of rooftop-mounted PV arrays.

A. But the presence of rooftop-mounted PV arrays has made cutting through a roof more challenging. In the past, the fire service had plenty of room to ventilate where it is most effective, directly above the fire. With PV arrays now covering large areas of roofs, firefighters are limited in where they can cut and where they can exit the roof. Since PV modules cannot be cut through, and moving them is time-consuming and potentially dangerous, rooftop PV systems pose some risks, mainly shock and trip hazards.

Q. If you would, please, turn to page 2. Starting with the third real paragraph, will you please read the paragraph starting with during daylight.

A. During daylight, there can be enough voltage and current to injure or even kill a firefighter who comes in contact with the energized conductors.

Q. And would you read the last sentence of that paragraph.

A. Here's an example. If a firefighter accidentally or deliberately axed through a string of twelve 44-volt DC modules, he or she will experience a potentially deadly surge of 528 volts.

Q. Mr. Beach, should the potential for injury or death to firefighters described in this section be considered in the cost of solar DG analysis?

A. You know, if you could quantify the likelihood of that happening and posing -- and then the likelihood that the firefighter wouldn't be trained in how to deal with it, I suppose you could consider it. But it seems like certainly something that should be considered from a safety perspective. But it is very difficult to quantify these kind of low frequency events.

Q. Are you suggesting that the assumptions underlying such an analysis might be difficult to be sure of?

A. Yes.

Q. And therefore you would not include it?

A. Well, I don't -- I haven't seen any -- it certainly is something that people should think about, as obviously they have here. But in terms of -- unless you assume that everybody who has a solar house is going to burn down, then it might not be worth considering.

Q. Will you please turn to page 3 of this document. Will you please read the first real paragraph on page 3.

A. The one that begins in a nighttime fire?

Q. Nighttime fire, correct.

A. In a nighttime fire where the attic space was exposed to severe heat damage, the conduit and wires inside may have become compromised. Some arcing could begin as the rising sun energizes the modules the following morning, a potential for starting a new fire. A qualified solar contractor should be called in to disconnect the arrays. Unfortunately, most PV companies do not have an on-call technician available, so the disconnect usually must wait until the next day, not always the safest measure. In this case, most fire departments will post a fire watch until a qualified contractor can ensure that the array is disconnected.

Q. Thank you, Mr. Beach.

Should the cost of additional first responder time required for homes with solar arrays that catch fire be included as part of the value of solar analysis?

A. I don't think -- that doesn't strike me as a very significant expense, given the current penetration of solar. I would be surprised if there are any fire departments that have added personnel as a result of people having solar on their house.

Q. Do you believe that if an expense is insignificant compared to the rest of value, rest of value of solar, it not be included in the value of solar analysis?

A. Probably, yes.

Q. Take a look at AIC Exhibit 17.

(Brief pause.)

BY MS. GRABEL:

Q. If you want to take a moment to review this document, Mr. Beach, you are welcome to.

Mr. Beach, what is in front of you is a 93-page report prepared by The Fire Protection Research Foundation entitled Fire Fighter Safety and Emergency Response for Solar Power Systems, is that correct?

A. Yes.

Q. And if you would turn to the third page in this document, under the forward, do you see that?

A. Yes.

Q. If you would go to the fourth paragraph down, second sentence, special thanks are expressed to U.S. Department of Homeland Security, AFG Fire Prevention & Safety Grants for providing the funding for this project through the National Fire Protection Association. Do you see that?

A. Yes.

Q. Mr. Beach, should the cost of time and resources invested by our federal government in researching, writing, and publishing this report how to fight fires on homes with solar panels be included in the value of solar analysis?

A. You know, I assume that this is a document that would apply nationally. So I would assume that if you -- you know, the federal government does lots of different kinds of research on lots of different topics. I think if you spread the cost of this probably important report over the whole country and the whole industry, for the purposes of what we are doing here I think it would probably not rise to the level of needing to be included.

Q. Would you include the time and resources spent by local and state agencies in implementing the recommendations of this report in the value of solar analysis for Arizona?

A. You know, if it turns out that those are significant, then that might be something that you would want to include. I am not aware that they are.

Q. Have you ever looked at them?

A. I have not looked at this particular issue, no.

Q. Look at your rebuttal testimony, Mr. Beach, on page 5.

A. Okay.

Q. You state on line 6 that, quote, a utility whose future financial returns are threatened by renewable DG faces a conflict of interest in presenting a balanced view of the long-term benefits and costs of DG resources.

Did I read that correctly?

A. Yes.

Q. Wouldn't it also be true that a solar company whose future financial returns are threatened by a change to the existing net metering, slash, volumetric rate design regime face a conflict of interest in presenting a balanced view of the long-term benefits and costs of DG resources?

A. Well, I think that, you know, that's why these matters are adjudicated by an impartial commission.

Q. And for such a solar company, isn't it in the firm's best interest to derive a methodology that results in a value of solar that is higher than the utility's retail rate?

A. Probably not, because the, I think the likelihood that a commission is going to increase the compensation to above the retail rate, especially in a market that is doing quite well, is probably very low. And I am not aware of any solar company that has proposed to increase compensation above the retail rate in a market that is -- where, you know, installations are occurring and the industry is growing. So I don't think that would be a likely position for the industry to take.

Q. If the value of solar is found to be below the retail rate, is that in the solar industry's best interests?

A. Well, you know, the problem is where you get in situations like Nevada where the compensation is reduced by such an extent that it no longer is economic for customers to install solar in that market, and then you basically kill the market. And that's certainly something that the solar industry is trying to avoid.

Q. And, again, the solar industry then would like a value of solar that preserves the economic benefits to its DG customers, correct?

A. We think there should be a balance between customers who participate in the solar market and customers who do not. We think that that's what will best assure the long-term growth of the market, is if we have both happy solar customers and happy nonsolar customers.

Q. You didn't answer my question.

A. Yes, I did. I said there should be a balance between the two. That was the answer to your question.

Q. Does the solar industry want to preserve the economic benefits of its transaction with DG customers?

A. Yes. There has to be economic benefits or customers won't put solar on their roofs.

MS. GRABEL: Thank you very much. No further questions.

ACALJ JIBILIAN: This is a good time for our morning break. So we will come back here in 15 minutes.

(A recess ensued from 10:33 a.m. to 10:51 a.m.)

ACALJ JIBILIAN: Let's go back on the record.

Mr. Patten, do TEP and UNSE have questions for this witness?

MR. PATTEN: I do, Your Honor. Thank you.

CROSS-EXAMINATION

BY MR. PATTEN:

Q. Good morning, Mr. Beach.

A. Good morning.

Q. Could you turn back to page 7 of your direct testimony. And at the bottom of that page you indicate that a thousand documented layoffs at solar companies took place in Nevada. Do you know how many of those workers worked for rooftop leasing companies such as SolarCity or Sunrun?

A. As I recall, the majority did, but not all.
Q. Okay. Safe to say the majority, though?
A. You know, 60 percent or something on that order.
Q. Okay. Do you know what the typical payback period was for rooftop DG purchased in Nevada prior to the Nevada decision?
A. Yeah. It was -- there is quite a bit of evidence on that in the record. It was somewhere between 15 and 20 years.
Q. Before the --
A. Yes.
Q. Before the Nevada decision, all right. Do you know how solar lease payments are set?
A. I know generally. There is quite a bit of variation, you know, in the industry. There is, you know, a number of different approaches. So, and my knowledge is only kind of general about how the lease agreements work.
Q. And when you say there is some variation, does that mean some customers get better deals than other customers?
A. Well, there is some -- there is certainly a difference from agreement to agreement. And there also are leases. There are PPAs. Some customers buy the system outright. Some customers get their own

financing. So there is the whole PACE financing that was alluded to this morning. So there are a variety of different approaches.

Q. All right. And you understand in Arizona that they use a solar lease and not a solar PPA, correct?

A. Actually, I was not aware of that.

Q. All right. Let's talk about solar leases now in terms of the rates that they set in those leases. Do you know what internal rate of return is used to set the solar lease rate?

A. No.

Q. And do you know what level of administrative or overhead costs are used to set solar lease rates?

A. You mean the solar companies?

Q. The solar companies.

A. No, I don't. I have no idea.

Q. And do you know net metering is factored into the solar lease rate?

A. What do you mean? How it is factored in?

Q. How it influences the solar lease rate.

A. No.

Q. All right. And do you know how they value the renewable energy credits that the solar leasing companies retain in calculating the solar lease rates?

A. No, I don't know what value they ascribe to those.

Q. All right. Solar panels are currently warranted for 20 to 25 years. Is that your understanding?

A. Yes.

Q. And do you believe there is an appropriate payback period for someone who buys a rooftop system?

A. Well, it certainly needs to be less than, you know, the warrantied life of the system.

Q. All right. But you don't really have an opinion whether it should be 10 years, 15 years, five years?

A. You know, obviously the shorter the payback the more attractive it is to the customer. That's, I think that's pretty obvious. And it does need to be less than the life of the system to make it economically appealing to the customer.

MR. PATTEN: All right. That's all I have, Your Honor.

ACALJ JIBILIAN: Thank you.

Mr. Loquvam.

MR. LOQUVAM: Thank you, Your Honor.

CROSS-EXAMINATION

BY MR. LOQUVAM:

Q. Good morning, Mr. Beach. How are you?

A. I am all right. How are you?

Q. I am doing really well. Thank you.

When customers with rooftop solar have reduced bills, they contribute less to utilities' fixed costs, correct?

A. Well, in the -- again, we had this discussion about fixed costs. And if you define fixed costs as being fixed in the short run, yes, they contribute less to those costs.

Q. And I am talking about test year fixed costs.

A. Yes.

Q. And in the next test year with the next rate case, responsibility for those fixed costs shifts to all other customers who don't have rooftop solar, correct?

A. Well, some of those costs may be shifted. But the key thing is that, over time, the utility will need to put in less infrastructure on its system as a result of the presence of distributed generation. That's something that is, you know, difficult to see except when you get cases like the Pacific Gas & Electric recently announcing that it was deferring all those transmission projects in part because of energy efficiency and rooftop solar.

But over time, over multiple rate cases, the presence of DG will allow the utility to build fewer generating plants and install less T&D infrastructure.

So over time there will be long-term benefits to customers. And there will not be, you know, there will not be a cost shift.

Q. No, and I understand the hypothetical benefits that TASC has paid you to discuss. But my question is: Purely from a rate perspective, coming out of the second rate case, rates will be going up for customers without rooftop solar because, in the immediate short term based on that new test year, fixed costs responsibility is shifted to them, correct?

A. Assuming that you -- that could happen assuming that, you know, you don't have a situation, for example, where, you know, the energy only, the fuel savings benefits are so big that there is savings for everybody.

Q. So setting aside the possibility of some fuel savings, all the other fixed costs are transferred, correct?

A. Well, again, I am not going to agree that it is all. Because there are, there can be immediately some capacity savings as well that may show up as soon as the next rate case.

Q. Have you done any studies on the time frame of capacity savings in APS's service territory?

A. Yeah. I think that if you look at our cost/benefit study, you know, we are assuming that there are those kind of benefits kind of continuously.

If you look at APS's, for example, your T&D infrastructure, it does vary based on your peak demand. And as your peak demand goes up, you add T&D infrastructure, so that if solar that's added this year reduces your peak demand, that's going to reduce your T&D infrastructure on a continuous basis.

Q. So if APS were to file a rate case and then in the next year file that second rate case, we would only be looking at the incremental DG penetration since that last rate case, correct, for purposes of this discussion?

A. Yeah. Whenever you file a rate case, you look at what your, at what your demand, what your demand is and what you expect it to be in the near future in terms of what you have to serve, so that if customers are conserving and they are enrolling in demand response programs and they are adding DG, all of those factors can combine to reduce your demand to the point that you actually would not -- you would defer projects instead of building them. You would have fuel savings. So there can be both capacity related as well as fuel savings benefit.

Q. And I appreciate that. That's in your direct. But, you know, there is a possibility we get done today, and I would really like to. If we don't, we don't. But longer question -- longer answers to otherwise pretty simple questions will guarantee we go into next week. So either way you want to play it.

I guess my question to you is this: Setting aside the possibility of a sliver of capacity savings on one-year DG penetration and the possibility there might be some fixed costs embedded in fuel costs, the cost responsibility for fixed costs shifts to non-DG customers in that next year rate case, correct?

A. Well, you know, rate cases only happen once every, what, three, four or five years. So there is a depreciable period.

Q. A rate case is going to happen anytime a utility wants to file them, correct?

A. I think it depends on the state. I am not sure what the rate case plan is in Arizona. But typically there are a few years between rate cases.

Q. Okay. So one, two, three years, the answer is still correct to my original question, correct?

A. I think I have already answered your question.

Q. Okay. I am going to pass out what I have labeled as Exhibit APS-14. I think that's the next number.

What was your participation in the Nevada proceeding that led to the decision memorialized in Exhibit APS Exhibit 11?

A. I was a witness in that proceeding for TASC both in the proceeding that led up to the decision that changed net metering and rates at the end of December 2015, and I was also a witness in the grandfathering phase of that case that happened in early February.

Q. Okay. I have placed or I have had placed in front of you what I have labeled as APS-14. And it is an article from Fortune Magazine dated April 12, 2016 entitled The Other Side of the Solar Firestorm in Nevada. And if you could turn to page 7 of 9, please.

Mr. Beach, do you agree that climate change is happening?

A. Yes.

Q. And the first full paragraph, it states:

We were one of the first states to say -- actually, let me go back a moment. And beginning on page 4 it begins a Q and A interview with Chairman Thomsen from the Nevada PUC. And page 7 is a continuation of that. So these are Chairman Thompson's words, and it begins on page 7:

We were one of the first states to say there is empirical evidence that there is this cost shift. The solar industry didn't want to hear that. They can try to discredit all the studies they want, but we have an open public case and all of the financial analysts and economists in this building that set rates said we found this cost shift and here is our proposal to mitigate it. A lot of the discussion leading up to this was about, "Is there a cost shift?" And I put that in the category of climate deniers. Let's move on from that.

Did I read that correctly?

A. Yes.

Q. Would you disagree with Chairman Thomsen's characterization of those who deny the cost shift?

A. Yeah. I don't -- I mean, again, I think I made clear earlier the Nevada commission relied on a cost of service study, and I don't agree that that's the right way to evaluate whether it is a cost shift or not.

Q. So if viewed from the perspective solely of the cost of service study, and I will set aside the value, and I understand you have a different opinion of that, but viewed from the perspective solely of a cost of service study, do you believe there is a cost shift?

A. In Nevada?

Q. No, as a general function under volumetric two-part rates.

A. You are asking me to evaluate net metering under

two-part rates using only a cost of service study?
Q. Yes.
A. I, you know, I would have to look at the cost of service study. I can't make a generalization that, you know, it would show a cost shift in every circumstance.
Q. Have you ever seen a circumstance in which it did not?
A. Well, there, there have only been a few statements that have tried to analyze this issue using a cost of service study. Nevada and Arizona are the only two that I am aware of. And so it is a pretty small sample.
Q. But neither of them -- or both of them showed a cost shift, correct?
A. Well, the utilities' studies, yes, showed a cost shift.
Q. In fact, the Nevada commission adopted that finding --
A. They adopted NV Energy's study.
Q. And -- okay. Do you have in front of you your direct testimony?
A. Yes.
Q. Can you turn to the study you have attached to it.
A. Okay.

Q. Which is the value of solar study you performed concerning APS's service territory, correct?

A. Yes.

Q. And it is based on all the available data you had regarding APS's rates and future forecasts, is that correct?

A. Yes.

Q. Could you turn to page 23, please. And in paragraph 6 you state: The primary cost of solar DG for nonparticipating ratepayers are the retail rate credits provided to solar customers through net metering, i.e. the revenues that the utility loses as a result of DG customers serving their own load.

Did I read that correctly?

A. Yes.

Q. Is this a cost shift, is this your statement as to what you believe the cost shift is?

A. No. This is a benefit/cost study. And the lost revenues are the cost side of the equation. The -- if there is a cost shift, it would be the difference between benefits and costs.

Q. Over a period of time?

A. These are a 20-year study.

Q. Okay. But it is the net of those two given that time frame in your study, correct?

A. Yes.
Q. If we use a different time frame there would be a different result, is that right?
A. Probably, yes.
Q. And if, for instance -- actually, strike that.
All of the benefits identified in your study occur in the future, correct?
A. Well, I did a study that looks ahead 20 years. So by definition, all the benefits are in the future. Some of them are in the first year. Some of them are in the 20th year. And they occur all, you know, during the course of that period.
Q. Did you identify which occur in the first year?
A. Yeah. I think if you looked at my work papers, you could see, you know, what the benefits were in the first year versus the tenth year versus the 20th year.
Q. But those weren't tied to specific projects; they were just simply levelized amounts over those years, right?
A. Well, to some extent they were. For example, some of them were based on, you know, fuel savings in a specific year. Like the T&D savings were based on regressions of APS's investments in T&D infrastructure as a function of peak demand, so that to the extent that peak demand is reduced by DG, those regressions show,

you know, kind of on average how much your spending on T&D infrastructure will be reduced.

Q. On average meaning it is not a particular project in a particular year but, instead, is an average or levelized or some sort of spreading of the hypothetical savings over 20 years, correct?

A. Yeah. In that case I did not identify specific projects.

Q. Did you for any of the capacity savings you identified or discussed in your report?

A. Well, the, you know, the generation capacity is based on combustion turbine as the kind of the marginal unit for APS. So that was based on the cost of a specific resource that APS would add as a source of capacity in the future.

Q. In the future, not year one?

A. No, not necessarily year one.

Q. Some undetermined period in the future hypothetically?

A. Well, there are capacity savings in every year of the 20 years. And you value those at the cost of capacity, which is the cost of a combustion turbine.

Q. Is this the lumpiness discussion where there is a lumpy acquisition of capacity by the utility and so you and Ms. Kobor from Vote Solar suggest that we value

capacity on a continuous basis?
A. Yes.
Q. So it was, it requires an affirmative decision by the Commission to look at future lumpy capacity savings on a continuous basis in order to have the year-to-year capacity savings that you are discussing?
A. Well, I don't think it is -- this is not a -- it is a method that's used to value all sorts of capacity additions that, especially for demand-side resources, that happen in small increments.
You know, you get capacity savings from putting in more efficient air conditioners. You know, doing one -- doing one efficient air conditioner is not going to defer a combustion turbine, but it can defer a small piece of a combustion turbine. And when summed over all the demand-side programs and all the DG resources, there will be enough there to defer, you know, those resources.
Q. Can you turn to page 13 of your direct, please.
A. Okay.
Q. Go to lines 26 to 28. It says: There are always cost shifts when a customer reduces the demand placed on the grid or shifts load to a different time period as the result of many types of actions that utilities and regulators encourage, energy efficiency,

demand response, or using DG to serve your own load.

Did I read that correctly?

A. Yes.

Q. So here aren't you saying that that DG used to serve a customer's load shifts costs?

A. Well, that's what, you know, that's what we are trying to assess in this methodology, is what are the cost shifts. Yeah, there are always cost shifts. Energy efficiency programs shift costs.

Q. Okay. But we are discussing DG used to serve a customer's load. That shifts costs as well, correct, or do you want to change this testimony?

A. It can, yes.

Q. It can. It can or it does? Because you said there are always costs --

A. I think we established that the cost shift is the difference between the benefits and the costs. You know, the cost shifts can -- you know, you are very rarely going to find that the benefits and the costs exactly equal each other. So there will be a cost shift in one direction or another.

Q. If there is a cost shift that is not mitigated by a benefit, now or in the future, is that fair to customers who are now bearing that cost shift?

A. Well, that's a policy decision for the, you know, the Commission to make.

Q. What do you think?

A. You know, I think that there certainly can be resources for which there is a cost shift. And the Commission can find that there are, for example, societal benefits from those resources that are such that you are willing to live with that cost shift.

I know, for example, energy efficiency programs, a lot of them don't pass the RIM test and so they raise rates for nonparticipating customers, but because they pass the total resource cost test, the commissions will adopt them.

Q. So is it your testimony that it is not an issue of fairness or equity?

A. It is an issue that should be looked at by the Commission. But the fact that, you know, a resource doesn't pass the RIM test and raises rates for nonparticipating ratepayers should not necessarily mean that it is a resource that shouldn't be pursued.

Q. Okay. My question was about whether this is an issue of fairness or equity from your perspective.

A. It is an issue of fairness, yeah.

Q. So it is unfair potentially if customers who are non-DG customers experience a cost shift that exceeds the hypothetical benefits of rooftop solar?

A. Well, I think that's, you know, that's something that the Commission has to weigh. And the purpose of this methodology is to put all the information in front of it about what the long-term benefits --

Q. I understand the Commission needs to weigh it ultimately, but I am asking you -- you are the expert opinion, you have testified about this in numerous states -- is it an issue of fairness or equity?

A. In terms of finding that balance between participating and nonparticipating customers, yes, it is a matter of fairness and balance.

Q. And would it be unfair or inequitable for costs exceeding benefits to be shifted to customers without DG?

A. It could be.

Q. In what circumstance? Because we are talking about cost exceeding benefits, and I understand that's a hypothetical because you disagree with that concept. I am not trying to trap you there. I am just saying if, in fact, the costs exceed the benefits and those costs are then shifted to non-DG customers, is that an issue of equity or fairness.

A. It could be. And it could be a reason to make, as I have testified, it could be a reason to make changes in rate design to remedy that balance.

Q. In front of you is something marked as APS Exhibit 15 entitled, it is Chapter 9, Subsidizing Solar Technology Deployment. And it is part of an MIT study entitled The Future of Solar Energy. And this is the complete Chapter 9. And each chapter, I will represent, is distinct.

If you could, turn to page 225. Have you seen this document before?

A. I have read parts of this study. I haven't read the whole thing.

Q. Are you there?

A. Page 225?

Q. Yeah.

A. Yes.

Q. So the nonbolded paragraph on the right states:

Finally, as we have discussed at several points, because residential PV generation is much more expensive than utility scale PV generation, the subsidy cost per kWh of residential PV generation is substantially higher than the per kWh of subsidy cost of utility scale PV generation. There is no compensating difference in benefits and thus there is simply no good reason to continue to provide more generous subsidies for residential scale PV generation than for utility scale PV generation.

And it continues on the next page:

Net metering with per kW charges to cover distribution costs is an important reason why residential PV generation is more heavily subsidized than utility scale PV generation. In addition, net metering raises equity issues: it is far from obvious that it is fair for consumers with rooftop PV generators to shift the burden of covering fixed distribution costs to renters and others without such systems.

Did I read that correctly?

A. Yes.

Q. Do you agree with MIT's statement here?

A. No, I don't.

Q. So they are saying it is far from obvious it is fair, and you just said there could be a fairness issue. How or why do you disagree?

A. Well, I, you know, I don't agree that the subsidy costs per kilowatt hour of the residential PV generation is substantially higher than the per kilowatt hour subsidy cost of utility scale. You know, I have looked at that issue in, you know, in Colorado for example and basically found that the benefits, the net benefits were roughly the same for rooftop and utility scale. So I, you know, I disagree with their conclusion here as a matter of, you know, the way they did their analysis.

Q. So you are saying it is an equity issue or isn't?

A. I am not clear what you mean by whether it is an equity issue or not.

Q. Okay. Well, let's figure that out. Could you turn to page 5 of your direct testimony. At lines 5 to 8 you state:

If the utility's lost revenues and program costs are greater than its avoided cost benefits, then rates may rise for nonparticipating ratepayers in order to recover those costs. This can present an issue of equity among ratepayers.

Did that I read that correctly?

A. Yeah, and I think that's what we have just been discussing.

Q. Okay. So you agree with this statement but not MIT's version of this statement?

A. Well, I don't, I don't -- you know, I haven't gone through the MIT's numbers that led them to that conclusion. So I don't necessarily agree with the MIT study.

Q. So you disagree with the portion of MIT's concern that concerns the subsidy per kWh analysis?

A. I disagree with their comparison between rooftop and utility scale, that there are, there is inherently more of a subsidy involved in rooftop than in utility scale.

Q. If the savings don't materialize that you forecast in your study, then the cost shift remains unmitigated, correct?

A. In other words, if there were some reason there were no benefits at all from solar, then there would be only costs, is that the hypothetical?

Q. I am saying if the savings identified in your particular study regarding fixed costs, capacity savings, if those don't materialize, then the cost shift will remain unmitigated, correct?

A. Well, I think there is always some uncertainty when you are doing forecasts and projections. There are certainly ways to, you know, try to bound uncertainty. You can use sensitivity analysis. You can look at forward market prices if you are concerned about the robustness of some of the forecasts.

But I think it is, it is, the idea that there just wouldn't be any benefits at all is kind of ridiculous.

Q. And I understand that position. And I am not saying that, asking you to adopt that. But I will say it this way. To the extent that the savings do not materialize, the cost shift is thus concomitantly reduced or unmitigated, correct?

A. Well, for example, you know, your hypothetical is assuming that the cost side is remaining constant. And let's say that the benefits don't turn out to be as high as I projected them to be because natural gas prices were lower. Well, natural gas prices also have a big effect on utility rates. So if natural gas prices are lower, it means utility rates are not going to be as high as I forecasted. And that's going to affect the cost side. So something like that will affect, you know, both sides of the equation.

Q. And I'm not really talking about the energy savings, which is the basis for the equivocation you just had. I am referring to the fixed capacity costs.

If, for instance, the transmission lines and the specific routes and the specific types of plants that APS has forecasted in its IRP aren't needed for whatever reason, customers don't move into the particular area of the valley that form the basis of those forecasts or load growth does not occur, or everyone decides to move to SRP's service territory, in those circumstances, or to the extent that those circumstances occur and reduce these forecasted capacity benefits, the cost shift is similarly unmitigated?

A. You know, I agree with that. I also, but I would add that it could happen the other way, too. Everybody could face their panels west. And you could have cheap storage technologies that increase the capacity value of solar. People could install this stuff due to a well planned utility program in the parts of its service territory where it is most needed and it has a higher value than average. Those could also happen and result in higher benefits than I have projected.

Q. Are you aware of any commission in the country that has used long-term forecasts to set rates?

A. We are not setting rates here. I think I made that clear in my introduction.

Q. I understand that. My question is about setting rates. Are you aware of any commission in the country --

A. Some commissions --

Q. Sir, sir, if I could finish, because talking over each other isn't great for the court reporter.

Are you aware of any commission in the country that has used long-term forecasts to set rates?

A. Well, California and Nevada used long-run marginal costs to set rates. So to some extent those are based on long-term forecasts.

Q. And do you know what the time frame of those long-run marginal costs are?

A. California tends to look out on the order of five years.

Q. Do they true them up?

A. What do you mean by true them up?

Q. Meaning once they start getting to the years they previously forecasted, they look at actuals and make sure customers are held harmless.

A. No, they don't do that. They, they certainly true up things like fuel costs. And California has full revenue decoupling. So they take out the effective sales fluctuations.

Q. Okay. And are you aware of any commission or other body that has used a value of solar model to set rates?

A. To set rates?

Q. Yes.

A. Not to set rates.

Q. Are you aware of any commission or body that has used a value of solar tariff to approve and continue net metering?

A. Well, again, I -- you know, California made a significant effort to do exactly this kind of analysis for -- through its public tool and took a lot of evidence on the benefits and costs in California. They did not in the end, I think as we have discussed, they did not rely on that evidence. But it is certainly my anticipation that they are going to continue to look at those kind of numbers in the future.

Q. But as you are sitting here today, you are not aware of any body or commission that has used a value of solar analysis to vet net metering and decide to keep it going?

A. Well, yeah. Colorado did. Colorado looked at -- we did a benefit/cost study in Colorado and participated in some extensive workshops with Xcel Energy over an 18-month period. And the outcome of those workshops was that the Colorado commission decided to maintain net metering in Colorado.

Q. Was that an evidentiary process?

A. It was not an evidentiary process. It was a workshop process.

Q. What --

A. It was in front of the Commissioners, though.

Q. What is a prosumer?

A. A prosumer is a customer who both produces and consumes energy.

Q. And a rooftop solar customer is a prosumer?

A. Yes, they are an example of a prosumer.

Q. And page 11 of your direct, you discuss the three states of a rooftop solar prosumer customer?

A. Yes.

Q. And those three states are the retail customer state, the energy efficiency state, and the power export or net metering state, is that right?

A. Yes.

Q. Are you aware of any other customer class in APS's service territory also whose service or load characteristics involve or incorporate these three states?

A. Probably not.

Q. So when customers export power to the utility from a rooftop solar array, you testified earlier that title transfers to the utility, correct?

A. Yes.

Q. And that's the same as when a wholesale supplier of grid scale power exports power from their facility to the grid as well, correct?

A. Yes.

Q. In both instances title passes to the utility?

A. That's my understanding.

Q. And then the utility resells that power to other customers, correct?

A. Yes.

Q. And so in both circumstances, aren't both acting in a wholesale capacity?
A. Well, in the respect that the power has been transferred to the utility, whether that is exactly how wholesale transactions are defined by FERC, I would have to ask a lawyer.
Q. How long have you been in this industry?
A. 35 years.
Q. And have you ever seen a wholesale trans -- have you seen a lot of wholesale transactions? Have you had experience with them?
A. Yes.
Q. And do you feel yourself qualified to opine on what is a wholesale transaction and what is not?
MR. RICH: Objection, Your Honor. He is asking -- it is a legal question. The witness already stated that requires a legal conclusion and he is not an attorney.
ACALJ JIBILIAN: Sustained.
BY MR. LOQUVAM:
Q. Okay. You testified earlier that all of the benefits in your study are uncertain, right?
A. You know, I would not characterize benefits as uncertain. They certainly are based on forecasts. But, you know, the fact that rooftop solar is going to

produce fuel savings by displacing natural gas, the fact that it is going to reduce line loadings on the utility's system, I don't think those are uncertain.

Q. Okay. Are you familiar with APS's position in this matter regarding the value of solar?

A. Yes.

Q. And that APS doesn't dispute that rooftop solar displaces the need for other energy sources in terms of actual fuel burn in natural gas and also that line losses provide -- or saved with rooftop solar?

A. Yes.

Q. So for this discussion, let's not talk about fuel or line losses, because that's a point of agreement I think between the parties. Okay?

A. Yes, I think that's right.

Q. So I am talking about all of the other benefits identified in your study. Those are all inherently uncertain, correct?

A. You know, I am not going to characterize them as inherently uncertain. There is a pretty direct relationship between the growth in the utility's peak demand and adding generation, transmission, and distribution capacity. So to the extent your load grows quickly, you add more infrastructure. To the extent your loads grow less quickly, you add less. And that's not -- I don't characterize, I wouldn't characterize that as uncertain.

Q. And that's fair. And I am not saying whether -- it is not binary like there are or are not benefits. I am just talking about the overall magnitude or quantity of benefits. That is inherently uncertain, correct?

A. Yeah. I don't disagree that, you know, there will be a range of opinions about, you know, for example, what are your marginal transmission costs, what are your marginal distribution costs.

Q. And I am not really talking about opinions either. I am talking about a forecast is made and then we don't know if it is accurate or not because we don't actually know until we get to the point that was forecasted, the time.

A. And utilities, that's -- they are in the business of doing that all the time. And anytime you add a long-lived new infrastructure, hopefully you have engineers somewhere who are looking at your forecast, is this plant needed, you know, how much is load growing in this area, do I need to reconductor this line, do I need to upgrade this substation, do I need to add this generating facility. All of those questions are matters where you have to look long term into the future and make forecasts.

Q. And what are the assumptions used to develop, in your understanding, those forecasts regarding generation capacity?

A. Well, you look at what, you know, how much load is growing. You look at, you look at, you know, the resource mix that you have. You look at when plants are going to retire. You know, you look at your resource portfolio, typically the kind of things you look at in an IRP.

Q. Does the assumption include projected load growth?

A. Yes.

Q. And it includes where customers might move?

A. Yeah.

Q. And it includes customer usage patterns?

A. Yes.

Q. And all of these are inherently unknowable, correct?

A. They are inherently unknowable. But you have to make, you have to take a crack at it if you are going to do, if you are going to do any kind of plan.

Q. For planning, you are right. So those forecasts based on those assumptions that are inherently unknowable, those form the basis of your projected benefits, correct?

A. You know, I relied upon, to a great extent I relied upon the APS IRPs. So that's, that was a readily available, hopefully internally consistent set of assumptions about your future need for resources.

Q. I understand that. It is those forecasts, those uncertain forecasts that form the basis, the exclusive basis of your projected benefits, correct?

A. Well, I wouldn't say that I took everything from your IRP, but that was certainly a major source of the data I used.

Q. And to the extent that those forecasts are unknowable and those are the basis for your projected benefits, wouldn't the project benefits also be unknowable?

A. Well, again, I don't -- I am going to disagree with your characterization of what is in your IRP as something that's unknowable. You know, I don't think you do an IRP if you were just coming up with something that was unknowable.

Q. Would you turn to page 9 of your rebuttal testimony. And so I am clear and the record is clear, we discussed generation capacity forecasts, the relationship that we just described between the assumptions of the forecasts and how those drive your benefit calculation, that's true for transmission and distribution capacity as well, correct?

A. Well, the T&D benefits that I looked at were basically driven by peak demand estimates both for at the system level and at the individual customer class level for APS.

Q. I understand. But I am just saying that previously I limited my question to generation capacity savings, and I just want to know whether the underlying relationships between the forecast and the assumptions and your benefits are consistent within generation, T&D, meaning for distribution you still made assumptions about customer load growth and where customers go and customer usage patterns, and the same for transmission, correct?

A. Yeah. I mean the details of the calculations are different for each of those. But, you know, I did make assumptions about the relationship between load growth and those costs.

Q. So on page 9, lines 20 to 22 of your rebuttal, you say: Finally, because renewable DG is a long-term resource, evaluating its cost effectiveness necessarily must involve long-term forecasts of many variables which are inherently uncertain.

Did I read that correctly?

A. Yes.

Q. It continues, in addition, the analysis necessarily involves comparing different resource scenarios, many of which will be counterfactual, is that right?

A. Yes.

Q. So given how we have counterfactual scenarios in a variety of different inherently and uncertain variables, why would it be reasonable for the Commission to rely on your benefit forecasts?

A. Well, it is exactly what the Commission does when it assesses any kind of long-term resource. You have to use forecasts and you have to, you have to look at counterfactual examples of, well, if I don't build this plant, what else would I do. And if you, if the plant that you decide to build, you may decide to build it because it is going to be cheaper than some other resource, but you will never build that other resource. That's the counterfactual. You will never really know what that other resource might have cost.

But those are the kind of analyses that, you know, we do all the time when we plan long-term resources. This is no different than building a new generating plant or adopting a longer term demand response program.

Q. There is a key difference, though, right?

Because those other resources that are procured by the utility only fit a specific need, and only actual costs are passed through to customers, correct?
A. I don't think demand-side, I don't think demand-side resources are meant to fit a particular need.
Q. Well, and I am not -- I am talking about a facility that generates energy and capacity. When utilities procure those, they only pass through actual costs to customers, correct, as a general matter?
A. As a general matter, when a utility builds a plant, it passes its just and reasonable costs as determined by the Commission --
Q. And isn't that --
A. -- through to rate base.
Q. -- a key difference between an IRP planning process and the procurement and costs responsibility for new generating facilities?
A. A key -- I am not sure. You asked me about a key difference between, I didn't catch what the two things were.
Q. The IRP planning process and these future forecasts that drive a lot of your analysis and the notion that customer cost responsibilities is only tied to actual costs.

A. No, I don't think there is, I don't think there is a difference there. You know, you can, you can decide to build a new generating plant under a certain set of assumptions and, you know, those assumptions, and it may be cost effective under those assumptions, but those assumptions may turn out to be wrong and you may end up having built a plant that turns out to be more expensive than what you -- the alternatives that you could have built.

But, you know, nonetheless you make the effort to assess the benefits and costs before you commit substantial ratepayer dollars.

Q. If net metering is sustained as a result of your cost/benefit analysis, that will determine the amount to which non-DG customers pay for this retail rate credit, correct?

A. Yeah, that would, yes.

Q. So although we talk about -- strike that.

Although you talk about in your testimony this is a screening tool to assess the reasonableness of net metering, it is not simply a screening tool; it actually directly translates into the rates paid by non-DG customers, correct?

A. In the same way that evaluations of new utility generating plants and finding out whether, finding out whether that investment is reasonable translates directly into costs for ratepayers.

Q. Except those are based on actual costs and net metering is not based on actual cost; instead, it is the result of your value analysis and the screening tool?

A. Well, what is found reasonable to put in rate base for new, a new electric generating plant is based on the value analysis in the certification and planning process.

Q. It is?

A. Yeah. You know, that planning process may determine that a nuclear plant that costs $5 billion is the right thing to put in place.

Q. Well, let me stop you there because we are not talking about planning. We are talking about costs being put into rate base and customer cost responsibility.

So for purposes of customer cost responsibility, it is the actual facilities and the costs for those facilities, those go through and are paid for by customers, right?

A. For a utility owned plant, yes.

Q. And net metering, you just testified, if it is sustained, that will directly influence how much customers pay, right?

A. Yes.

Q. But net metering is not based on costs?

A. Because the investment is made by your customers; it is not made by the utility in the case of net metering.

Q. I understand that. But non-DG customers are stuck with the bill and net metering is not based on cost, correct?

A. Well, it is -- I am not sure what you mean it is not based on costs.

Q. You state in your testimony that the goal here is to evaluate exports, right?

A. You know, that's certainly what differentiates distributed generation from other types of demand-side resources, are the exports, yes.

Q. But your analysis didn't look at export energy; it looked at total production of rooftop solar systems, right?

A. Yes, because the analysis is, as I said in my introduction, the analysis is considerably easier if you look at the, at all output rather than just looking at exports.

Q. But the data is available, right?

A. You know, I haven't tried to do an export only analysis in Arizona. And so I would have to rely on the good graces of companies like yours to get the data to do it.

Q. So you didn't try?

A. I didn't try, no.

Q. In this proceeding?

A. In this proceeding, that's right.

Q. What would an hourly analysis entail? Would it involve just simply evaluating when the export occurs in relation to utility peak?

A. Well, I think that, you know, one, the approach that California took that enabled -- you know, there have been three benefit/cost studies in California that have looked only at exports, one that we did and two that the consulting firm Energy and Environmental Economics did. The reason that those were possible is that the California PUC developed an avoided cost model for the investor owned utilities in California that is an hourly avoided cost model.

Q. And I understand that. But I am looking, I am comparing the methodology that you used in your study, which was assessing the total production in connection with the peak. And you used APS's IRP data for that.

And so if you were just only to use a subset of the DG production export only, would you similarly just look at what kind of exports occurred during the peak?

A. Yeah, possibly. I mean when you say the peak, I have to figure out, you know, what peak hours you are going to look at and things like that. There are a lot of details, but --

Q. So maybe the single hour of peak, maybe the top 90 hours of peak?

A. Or you could -- you know, there is a variety of ways to do it.

Q. What way did you do it in your study?

A. I used what is called a peak capacity allocation factor, where you look at all the hours that are within one standard deviation of the peak.

Q. Okay. And how many hours did that wind up being?

A. I think it is somewhere between 10 and 15 percent of the hours.

Q. And is that what APS used in its IRP?

A. I don't think so, no.

Q. So you changed the methodology? Although you used APS's numbers about contribution to peak, you applied them to different hours that APS didn't use?

A. No, I didn't. No. I think APS has done, did an effective load carrying capacity study. And, you know, I used a methodology that is simpler and more transparent than that.

Q. Would you agree that the ELCC, the effective load carrying capacity, is a reasonable way to do this type of analysis?

A. It could be. The problem with it, it is not very transparent. You need to use a reliability model that is, you know, requires a lot of assumptions and is not transparent except to the person who uses it.

Q. But APS's use of the ELCC produced its IRP, and you relied wholly on APS's IRP. So it was good enough for that, right?

A. Well, I didn't say I relied wholly on APS's IRP. I used, you know, some of the data from APS's IRP. In terms of the capacity contribution, I used a different analysis because, you know, that I thought was more transparent.

Q. That's actually kind of confusing. Can we go to the study attached to your direct. And on page 6, underneath the paragraph entitled Benefits, just below the middle, you say: However, the 2014 IRP also shows continued growth both in energy efficiency and demand response programs and in distributed solar resources between 2014 and 2019 such that new demand-side resources developed in 2014 to 2019 will contribute 986 megawatts to meeting APS's peak demands by 2019.

Did I read that correctly?

A. Yes.

Q. Did you use that 986 megawatt number to develop your projected benefits?

A. No.

Q. Why did you reference it then?

A. Well, I just, I referenced it just for the -- to make the point that energy efficiency, demand responses, and distributed solar, even under APS, the way APS did it in the IRP, is going to contribute a substantial amount of capacity.

Q. Are you aware of the split between EE and DG that comprises that 986 megawatts?

A. I am sure it is in the IRP. I don't remember what it exactly is.

Q. We can answer that question. APS's 2014 IRP is publicly available and I have copied here just simply what is on page 8 of that document, entitled Table 1, summary loads and resources. Do you see that?

A. Yes.

Q. Is this the same table that you referenced in your study?

A. It appears to be, yes.

Q. And then on 2019, in the middle it says energy efficiency, 877 megawatts; distributed energy, 109 megawatts, for a total of 986. Did I read that correctly?

A. Yes.

Q. So does this mean that the split is actually heavily weighted towards energy efficiency?

A. Yes.

Q. Earlier you discussed the concerns with the ELCC and transparency. It is a commonly used tool in the industry, is that right?

A. Yeah. It is widely used, yes.

Q. And has there been a systemic concern about its accuracy?

A. Yes, I think there are systemic concerns about its accuracy.

Q. Continuing concerns or historical concerns?

A. I would say both.

Q. So it is your testimony today that the ELCC is too flawed to use?

A. Yeah, my testimony is that there are, there are other methods to assess the capacity value of solar resources that are much more transparent than ELCC.

Q. Okay. Setting aside transparency, I am talking about accuracy. On the basis of accuracy, do you think ELCC is a reasonable way for utilities to plan?

A. You know, I have my doubts about whether it is. There are a number of issues about, you know, for example, how scheduled maintenance is used in ELCC studies. There are issues about using weather normalized and particular meteorological year data in ELCC studies instead of using actual load and resource data that I think make it problematic.

Q. Export energy is different than self-consumed energy, right?

A. Yes.

Q. And the difference is -- can you describe the differences?

A. Well, self-consumed energy is the portion of DG output that's used by the customer on-site, and export is what is sent out to the grid.

Q. And would you agree that the timing between the two is different viewed from a system perspective?

A. There are some timing differences, but, you know, whether they are material or not I think is an empirical question.

Q. Meaning data would determine that?

A. Yeah.

Q. Are you familiar with Brad Albert's testimony in this matter?

A. Yes, I did review that.

Q. And his rebuttal testimony where he describes the timing differential between export and self-consumed energy?

A. Yes.

Q. If you could, turn to that. It is his rebuttal testimony, page 16. I am not sure which exhibit that is. I think it is 6.

ACALJ JIBILIAN: It is APS-6.

THE WITNESS: Okay. I have his testimony.

BY MR. LOQUVAM:

Q. So if export energy occurs at a different time than self-consumed energy, would that have different implications for capacity benefits provided by rooftop solar energy?

A. I mean, if you do your capacity avoided cost on an hourly basis, it could have a difference, yes.

Q. And would that be material for purposes of assessing the value of solar?

A. Well, again, you know, I have -- E-3 did a net metering study in California using an hourly avoided cost model, and they found very little difference in the avoided cost between exports only and all output --

Q. Did you create that study?

A. I didn't create it. I --

Q. Did you understand what the methodology was behind it?

A. Absolutely, yes.

MR. LOQUVAM: Your Honor, I move to strike his references to this study. If we want to have it introduced, I am happy to look at it, but I think it is -- it distorts this discussion because we don't have any ability to assess its assumptions.

MR. RICH: Your Honor, well --

MR. LOQUVAM: It is also hearsay.

MR. RICH: This is an administrative proceeding and we have a tremendous amount of hearsay that has been introduced to date.

He said he understands the study. I am not sure that -- I would be happy to review the last question to see what gave rise to that, but I don't believe there is any reason to strike it.

MR. LOQUVAM: My point is solely that there is these broad claims on topics that are central here that we don't have the ability to actually look at any of the these assumptions. They are just kind of from the hip: Oh, this was said.

MR. RICH: Your Honor, the time to object to the testimony is long since passed obviously as well.

MR. LOQUVAM: The first time the E-3 study from California was mentioned was this morning in his intro.

MR. RICH: And he testified he is very familiar with it.

MR. LOQUVAM: And I am not worried about his interests.

ACALJ JIBILIAN: I would like to go back to the question that elicited the response, and the response, too, if you could read it.

(The record was read by the reporter as requested as follows:

Question: And would that be material for purposes of assessing the value of solar?

Answer: Well, again, you know, I have -- E-3 did a net metering study in California using an hourly avoided cost model, and they found very little difference in the avoided cost between exports only and all output --)

ACALJ JIBILIAN: I don't feel it is necessary, it is not necessary to strike the answer. However, since that study is not in evidence, I don't see what legal argument could be made based on that study. So that's -- I don't think that we need to strike the answer to have that result.

MR. LOQUVAM: Fair enough.

BY MR. LOQUVAM:

Q. That study, the E-3 study, was based on California data and California utility specific peak information, is that right?

A. Yes.

Q. But other than that study based on California information, would you agree that if export energy occurs at a different time than self-consumed energy it would have different implications for capacity savings for the utility in question?

A. I am going to say it could, but, again, that's an, it is an empirical question. And, you know, generally, if you look at, for example, if you look at in my testimony Figure 5 that we talked about, the three states of net metering, you know, exports tend to happen more in the middle of the day, whereas the self-consumption can take place over the full period in which the system is producing. So you may get more self-consumption first thing in the morning and in the evening.

You know, the self-consumption in the evening could be quite valuable. So could the solar generation that takes place in the middle of the afternoon. So, again, it is something, the exports that take place in the middle of the afternoon could be quite valuable as well. Again, it is an empirical question. You need to look at it --

Q. Sure.

A. -- with the detailed data.

Q. Sure. We are focusing on exports, though, right?

A. Yeah. If you just focused on exports, and to find out whether there was any significant difference between exports and all generation, you know, you would need to do the study both ways and then see if there is a difference.

Q. And utilities build towards to serve peak demand and load, right?

A. For generation and transmission. For distribution they tend to build for peak demand at a more localized basis.

Q. Okay. But it is demand, whether it is noncoincident or coincident demand, that's what they build towards, right?

A. Yes.

Q. And are you familiar when APS's peak demand was in 2015?

A. I think I saw some data on that. And I believe you have been peaking in the hour between 4:00 and 5:00 p.m. in the afternoon.

Q. If I -- well, I will represent to you it is on August 15 at 5:00 p.m. last year. And that's in Mr. Albert's testimony, subject to check, if you will accept that.

A. Yeah.

Q. So let's actually talk about Figure 5 on page 11 of your direct. And I don't have a ruler, but that solar output, the sort of uncolored line above, when did that end, when did that export end in this diagram?

A. You know, it ended about 5:00 p.m.

Q. So I know this is not APS's. This is an illustrative. But if this were the profile of a typical rooftop solar customer for APS customer in 2015, would that mean that export energy did not contribute to APS's peak needs if this was an August 15 day?

A. Well, if it was, if it was, if your peak was at -- well, first all, let me -- it might not have contributed to the peak hour, but it would have contributed to the hours immediately before the peak. And those can be, you know, very important hours, too.

In my -- and I think most utility planners realize that you don't look just at the peak hour; you look at the set of hours that are most critical for the system.

Q. To determine using an ELCC?

A. Well, that can be one way to do it, or the PCAF method that I use could be another way.

Q. But for this day in particular, it did not contribute to peak?

A. You know, I also observe that this shows a south-facing PV system. For example, the PV system that's on my house is almost due west, and it peaks at 3:00 p.m. in the afternoon.

Q. I understand. I am focusing on this diagram right here, south-facing system.

A. That's right.

Q. It didn't have any export at 5:00 p.m., which, if this was an APS scenario, it would not have contributed to APS's peak demand on that day?

A. To that one peak hour it would not have contributed, yes.

Q. And then I think I asked you to turn to Mr. Albert's rebuttal testimony, to page 16, lines 20 to 25. It says:

And when APS hit its annual peak load at 5:00 p.m., rooftop solar was exporting only 8.8 megawatts to the grid, or about 5 percent of the aggregate nameplate capacity of all residential rooftop solar systems over the course of the day. Rooftop solar customers self-consumed 74 percent of their solar output and only exported 26 percent.

Did I read that correctly?

A. Yes.

Q. So for purposes of APS's peak demand in 2015, on that peak hour, would you agree that only 8.8 megawatts of exported rooftop solar energy should be counted for purposes of peak demand reduction?

A. No. I think, as I just testified, you are talking about one peak hour. And the contribution of solar to reducing the peak should not be measured just on the contribution to this, to one peak hour. It should be measured more broadly across a broader set of peak hours.

Q. I understand that. And so would you agree that if that peak contribution was measured over the broader number of hours, would that be an accurate data set for purposes of establishing how export energy contributes to peak demand reduction?

A. I mean it would be -- I mean we would have to obviously agree on the details.

Q. Why wouldn't it be?

A. Well, I think we just had a discussion about whether -- you know, various methods for looking at contribution to peak and, you know, there are different approaches. We just had a discussion about whether ELCC is a good approach or not. So I would reserve judgment on the approach used.

Q. Fair enough. But let's say we use the top 90 hours of a utility's peak in a given year, meaning, you know, based on actual data, metered data, it is only the top 90 hours, which is a lot of hours. Would it be reasonable to aggregate and look at the data for export energy on those top 90 hours and say this is the only data set we need to establish whether and how export energy contributed to peak demand?

A. You know, I am not going to commit to the top 90 hours either. That's only 1 percent of the top hours. My judgment is it should be a broader set than that.

Q. How much broader?

A. Well, the method I used looks at 10 to 15 percent of the top load hours. So it is a broader set.

Q. And doesn't that dramatically increase the value of exported energy?

A. I didn't do an export only analysis. So I can't say.

Q. But you agree that if you had done it, it would have resulted in a different conclusion than your look at total production, right?

A. No, I am not going to agree to that.

Q. Oh, come on.

Have you heard testimony regarding peak shifting with further solar contribution?

Sorry. That was a really poor question. There has been testimony in this matter regarding the notion that the peak might shift as additional rooftop solar and actually grid scale solar is installed on a system. Have you heard that testimony?

A. I am aware of that concept, yes.

Q. Do you subscribe to that concept? Do you understand or believe it or can you comment on it?

A. It certainly can happen. You know, I have actually looked at the data for Hawaii. And you can see a shift in the peak in Hawaii, where they have, 20 percent of customers have rooftop solar. But it takes, it takes a pretty high penetration of solar to start to see that happen. I have looked for it in California. Very hard to ascertain at this point, even in California where we are at, you know, 5 percent penetration.

So it can happen. It also can be mitigated by things like west-facing systems. Or a small amount of storage combined with storage can, would have a big effect on that effect.

Q. Let's limit our discussion to rooftop solar however. You are saying that it is possible that peak shift occurs, it just requires a lot of solar penetration?

A. Yes.

Q. And once that peak shift occurs, would you agree at that point when the utility's maximum peak is occurring at night, solar is not contributing to peak reductions?
A. It takes a lot of solar to bring that about.
Q. Understand.
A. But if -- you know, my guess is that it would, there would probably be some hours that there would be some contribution leading up to a nighttime peak. But obviously, if the peak is happening at nighttime, solar's contribution to that would be substantially less.
Q. Zero? It is at night.
A. Again, I, you know, I --
Q. I am only talking about rooftop solar. Batteries I get; inverters, that's a different discussion. Rooftop solar nighttime production is zero, right?
A. Nighttime production is zero.
Q. And if the peak is at night, then the production and contribution to peak at that time is zero, right?
A. Again, you know, my view is that it is not just the peak hour, it is the hours leading up to the peak. So if there are hours leading up to the peak that also are high-demand hours and it is still daytime, then

there still could be a contribution.

Q. When utilities make planning decisions to build particular facilities, they use a set number of hours, right? I mean that's just what they do. Whether you agree with that or not, I understand you have disagreements with the methodology, but that's actually the costs they go incur, is that right?

A. Was your question do utilities have certain approaches to calculating a peak capacity contribution?

Q. I am focused more on the fact that they go build to establish the peak that they believe exists or their peak demands that they have developed with their methodologies.

A. Well, a peak demand is something that's recorded. I don't --

Q. We are talking about forecasting.

A. I am not understanding your question.

Q. Okay, fair enough. It was probably unclear.

Utilities develop plans on future capacity needs and then make procurement decisions based on those forecasts, right?

A. Yes.

Q. And it is their forecast, for instance, we need to serve XYZ load over the next several years because our forecasts for the peak demand during the hours in

question is X, right?
A. Yes.
Q. So if a utility is using the top 90 hours, that's the measuring stick for that particular utility in terms of the costs saved if rooftop solar reduces peak demand, right, regardless whether you disagree with the underlying methodology, right?
A. I am having a hard time understanding what the utility is using the top 90 hours for. I mean your peak demand is -- I mean it is possible that the utility could use a measure of peak demand that's different than just the load in the absolute peak hour to -- as a metric for how much capacity it needs on its system.
Q. I am pretty sure my question was unclear.
So when you do your value of solar study for APS, you are looking at APS's forecast for what their future capacity needs are, and you calculate a value of rooftop solar based on APS's stated plans for what it will build into the future, right?
A. Yes. I look at that to -- for example, to pick the, to pick the value of capacity, you look at the kind of resources that APS is going to add in the future, like a combustion turbine.
Q. And the timing of those based on APS's assessment of when peak demand will need additional

resources, right?

A. To some extent we look at that; although, you know, it is my view that you should look at the value of capacity on kind of a continuous basis, as we have discussed earlier.

Q. Fair enough. But I am focusing more it is APS's procurement decision that you are analyzing.

A. Yeah. I would, for example, I look at the IRP, and APS is adding the Ocotillo combustion turbine units. And so that's what I -- the way I modeled my marginal resource --

Q. And so --

A. -- capacity.

Q. -- if APS has established that capacity plan, then although you might have disagreements with APS's use of whatever planning methodology it uses, it is what it is, that's the actual capacity that's the bogey for purposes of establishing whether benefits will actually materialize in APS's service territory as a result of rooftop solar, right?

A. Well, that's what I used to calculate the marginal cost of generation capacity.

Q. So it renders moot whether you disagree with the ELCC or not because that's actually what APS is going to act on, so that's actually what the facts are going to be that you rely on, right?

A. No. I used that to establish the marginal cost of generating capacity. The capacity contribution of solar is based on my PCAF calculations, which is like we have gone through. It is based on a somewhat broader set of peak hours than the peak hour or the top 90 peak hours, and that determines what percentage of nameplate capacity of rooftop solar should be assumed to meet APS's peak demand needs.

Q. Using a different set of hours than what APS will actually act on seems to be putting your thumb on the scale, doesn't it?

A. No, because the -- what we are trying to do here is assess a customer-sited resource with an intermittent technology. And we are trying to look at the characteristics of that particular resource, I mean in comparison to a combustion turbine where you know that a 100 megawatt combustion turbine is going to generate 100 megawatts when you turn it on.

Q. Externalities aren't included in a cost of service, right?

A. Probably not, no.

Q. Probably not or no?

A. Well, you know, I guess by definition the word externality means it is external to the utility's cost

structure. So I would say no, it is not included.
Q. And there is no carbon tax or other source of immediate environmental cost that flows through the cost of service other than, for instance, maybe facilities like a selective catalytic reducer, right?
A. You don't install that for carbon. That doesn't take the CO2 out of your --
Q. Fair.
A. -- flue gas.
Q. Other than sort of facilities, there is no other environmental costs that flow through the cost of service?
A. Not Arizona, to my knowledge today.
Q. And so to the extent that those don't flow through the cost of service, customers aren't going to be responsible for those costs, right, through their utility rates?
A. In the short run, probably not.
Q. So when we assess and compare the difference between grid scale and rooftop solar facilities and the value of those two types of energy sources, externalities are irrelevant, right?
A. No, I would disagree with that. I think that there are different sets of externalities that apply to utility scale solar as opposed to rooftop.

So, for example, both utility scale and rooftop may have the same effect on reducing carbon. But rooftop solar has other external benefits that should be considered that utility scale doesn't. One of them is improving reliability and resiliency. Utility scale solar can't be part of a local microgrid that can enable critical loads to remain in service even if there is an outage to the utility system, whereas DG solar can. And that's a benefit, kind of an externality benefit of DG solar that rooftop solar does not have, I mean utility scale does not have.

Q. Can you quantify that microgrid benefit?

A. I have quantified it in other testimony. I don't believe I quantified it in this testimony.

Q. I don't think you did either.

Rooftop solar and grid scale provide the same -- involve the same technology, right?

A. Basically, yes.

Q. And they both produce energy fueled by solar energy, right?

A. Yes.

Q. And so from the perspective of all other customers, wouldn't, if the goal is to increase the amount of solar, wouldn't grid scale solar be a more cost effective way to obtain the value of solar?

A. No, because it is not necessarily -- because it is, you know, located in a different place than rooftop solar. Rooftop solar serves loads directly. And the power that doesn't serve the load on-site is exported to the grid where it is immediately consumed by the neighbors. That's a lot different than a utility scale plant that's located remotely, where the power has to be transmitted and distributed over the utility system to the customers.

Q. But an apples to apples comparison between the two types of solar applications is possible, right?

A. Yes. You can, you can certainly, you can add the marginal T&D costs onto the utility scale cost.

Q. So if the marginal T&D costs, after adding those to the value of rooftop solar, still don't come out ahead, wouldn't grid scale solar be the best option if the Commission is interested in furthering the penetration of solar in Arizona?

A. Well, I think that, you know, I think you should look at those numbers and see what the comparison is. And they may not be as far off as you -- when I looked at that issue in Colorado, the numbers were not significantly different.

And then there also are a lot of policy issues that I set forth in my testimony in terms of customer engagement and new sources of capital and competition and customer choice that also need to be considered.

Q. I understand, the Jeffersonian ideal of the solar farmer.

A. Yes.

Q. I understand that. My question is focused on cost and actual customer bills. These are real families who have to decide where they are going to spend what they make. And they are going to buy food and clothing for their children and school and energy costs.

And so when the Commission is assessing what is the most cost effective way to increase the amount of rooftop solar penetration, if we gross up the costs or the benefits of rooftop solar to account for T&D, and grid scale is still better, wouldn't that be the better policy option for the Commission?

A. Well, you also -- there is also a demand among customers to increase, to be able to be served by a higher penetration of renewables. And you just can't meet that with utility scale solar unless you are going to, you know, do a program where you directly allocate the utility scale solar power to the customer.

Q. Demand by customers who have average credit of 760?

A. You know, whatever. But you can't meet the demand of customers to be served by a higher penetration of renewables with utility scale solar unless you have some kind of community solar or program.

Q. On a cost basis you conclude that south-facing solar, excluding externalities, is a net cost to all customers, right?

A. The benefits of south-facing solar are not quite as high as the benefits of west-facing. So I think that, you may be right, that it is slightly less than, slightly less than the cost. I think the costs are like 17 cents and benefits of south-facing were 16, something like that.

Q. Page 22 of your study, and 23, the costs are 17.9 based on your analysis, whereas the benefits of south-facing solar, excluding externalities, stuff that does not flow through the cost of service, is 15.5, is that right?

A. Yes, that's right.

Q. So in that circumstance, with south-facing systems being a net cost to all other customers, would you agree that south-facing systems shouldn't get net metering?

A. No. You know, I think what it means is that you might want to think about a program that incents customers to install west-facing systems that have significantly higher value.

Q. Wouldn't net metering do that? If we canceled net metering for south-facing systems and only give it to west-facing systems, wouldn't that do that?

A. No. One thing you could do is require net metering customers to take service under time-of-use rates. And that will give people a strong incentive to face their systems west.

Q. But if they install them south nonetheless, then it is a net cost. So in that circumstance, under your own standard for at what point net metering should continue, shouldn't net metering be terminated for south-facing systems?

A. You know, I think that would be, when you -- I am not sure. What would you replace it with? If the difference between the cost and benefits is only a penny, you know, and the, or two pennies, the costs are roughly 18 cents and the benefits are 16 cents, you know, it wouldn't make sense to terminate net metering and only compensate them 2 cents.

Q. I understand that, sir. But even the benefits you have established are full of putting your thumb on the scale, using different methodologies and trying to expand these benefits as much as you can as an expert on behalf of the Vote Solar, and we are still below the cost that you identify. So why shouldn't net metering be cancelled for south-facing systems?

A. Because there are other things you can do. You could require time-of-use rates so you will get more west-facing systems. And my analysis shows that the costs of net metering for under time-of-use rates are about a penny below the cost under nontime-of-use rates. So you will help address -- if you think that there is a net cost, you can address it by requiring time-of-use rates.

You also can do things like putting on a minimum bill so that customers who install large systems relative to their usage will contribute to a minimum amount of costs.

Those two recommendations I make, I think, would bridge that difference that you just pointed out.

Q. Okay. But you wouldn't apply your standard of, if net metering is considered to be cost effective based on a cost/benefit analysis it should continue, you wouldn't apply the reverse of that; is that what your testimony is today? Instead, you would say no, we should continue to install south-facing systems but, instead, just apply other solutions?

A. Well, that's why we are doing this test, is to find out whether we need to make adjustments to things like rates --

Q. And not net metering?

A. -- and rate design.

Q. I thought that's what the discussion was.

A. No. You can affect the balance of cost and benefits for net metering through rate design. You don't have to get rid of net metering.

Q. But meanwhile, if net metering persists for south-facing systems, all non-DG customers will be paying in the short term increased rates to fund net metering, right?

A. Well, there also are, you know, societal benefits, which are significant. And the Commission needs -- if the -- if you are short by a penny or two, the Commission should evaluate whether it is worth funding that cost shift because of the external benefits. For example, energy efficiency programs often raise rates for customers. And commissions accept that because of, because of the external benefits of energy efficiency.

Q. And, meanwhile, the benefits that you have identified here that still don't overcome the stated costs are based on forecasts that are inherently uncertain, right?

A. Forecasts always have a certain amount of uncertainty.

Q. And what if those forecasts are wrong and customers without DG will have been paying that, something you even admit is not cost effective, isn't that unfair? Doesn't that raise issues of equity?

A. Well, the forecasts could be wrong in the other direction, too. Natural gas rates could go, natural gas prices could go up substantially. It could turn out that climate change is actually happening faster than we think. So, you know, forecasts are inherently uncertain. Sometimes they turn out to benefit people as well as cost people.

MR. LOQUVAM: Thank you, Your Honor. No further questions.

ACALJ JIBILIAN: Would you like to move your Exhibits APS-14 through 16?

MR. LOQUVAM: Please, Your Honor, I move all of those for admission.

ACALJ JIBILIAN: Is there any objection?

(No response.)

ACALJ JIBILIAN: APS-14 through 16 are admitted.

(Exhibits APS-14 through APS-16 were admitted into evidence.)

ACALJ JIBILIAN: And would AIC like to move its exhibits?

MS. GRABEL: I would, Your Honor. Thank you.

ACALJ JIBILIAN: AIC-8 through AIC-17, is there any objection?

(No response.)

ACALJ JIBILIAN: AIC-8 through 17 are admitted.

(Exhibits AIC-8 through AIC-17 were admitted into evidence.)

ACALJ JIBILIAN: And after we come back from lunch, I hope to hear from the parties regarding any procedural recommendations. We will see you back here at 1:30.

(A recess ensued.)

(Colette Ross, Certified Reporter, was excused from the proceedings.)

(TIME NOTED: 12:24 p.m.)

(The afternoon session resumed at 1:30 p.m., reported by Gary W. Hill, Certified Reporter.)

ACALJ JIBILIAN: Let's just go back on the record, and there were some procedural issues that the parties wanted to raise before we continue with the cross-examination.

MS. SCOTT: Your Honor, we have relooked at some of the dates for the resumption of the hearing in June --

ACALJ JIBILIAN: Okay.

MS. SCOTT: -- and we're now looking at June 8 for foundational testimony by APS and TEP and UNSE.

ACALJ JIBILIAN: For TEP and UNSE, a different case?

MS. SCOTT: No, they have responses to the same data requests.

ACALJ JIBILIAN: Oh, okay. I'm sorry, I thought --

MS. SCOTT: And so they will be presenting their responses on that day as well as APS.

ACALJ JIBILIAN: So TEP, UNSE and APS will each have a witness on June 8?

MS. SCOTT: Yes.

ACALJ JIBILIAN: Okay.

MR. PATTEN: I think our witness would be one witness for TEP and UNS.

ACALJ JIBILIAN: Right.

MS. SCOTT: And then we would propose, Your Honor, that parties have the option of either filing a written response to the testimony that's presented that day or, if they want, they can present a witness to submit responsive testimony, and the date that we're looking at for that is June 13th.

ACALJ JIBILIAN: Okay.

MS. SCOTT: And then we've also looked at a briefing schedule, and I think everyone is in agreement that since we have most of the evidence on all of the issues except this one outstanding issue, parties can start working on the briefs after the close of today's hearing. And so we've agreed to an opening briefing date of June 20th, which is a week after the witnesses appear on the 13th.

ACALJ JIBILIAN: Okay.

MS. SCOTT: The reply brief has been subject to some discussion. I think most people can do it on the 30th or, I believe, the 1st; however, Mr. Rich would like additional time, I think. So that's -- we're still more or less talking about that date.

ACALJ JIBILIAN: What date do you propose, Mr. Rich?

MR. RICH: Your Honor, I was proposing the 8th.

ACALJ JIBILIAN: Okay.

MR. RICH: There are several -- there's another brief and several other things that are due the end of June, and I'm just trying to manage that schedule. And then I know that caused RUCO heartburn because they were not going to be in the office, I believe -- I'll let Dan answer for himself -- but on the 8th. And so he suggested if it was the 8th, then it should be the 11th, that Monday.

ACALJ JIBILIAN: But -- okay.

MR. PATTEN: Your Honor, I don't agree with Mr. Rich on many things, but the 8th would be preferable as well.

ACALJ JIBILIAN: And, Mr. Pozefsky, you would be willing to do it on July 1st?

MR. POZEFSKY: Right.

ACALJ JIBILIAN: Well, could you just get it ready and have someone file it for you on the 8th?

MR. POZEFSKY: Well, I don't know that, Your Honor, because normally that would be Jordy Fuentes, but he's going to be out of the office, too, that week.

ACALJ JIBILIAN: Well, I mean, couldn't you have it all ready to go and just have an administrative assistant do the filing?

MR. POZEFSKY: You know, without speaking to, again, my experts, et cetera, I just don't know. I'm kind of --

ACALJ JIBILIAN: I think that the 8th seems perfectly acceptable. So somehow, I think, that you might be able to get it done. If you were willing to do it on the 1st, I don't see the problem with the 8th.

MR. POZEFSKY: Okay. I guess that decides it.

ACALJ JIBILIAN: Okay. So we do have this room available on June 8th and also on June 13th.

Would there be prefiled testimony or would the testimony just be from the stand? Is that something that the parties have discussed?

MR. LOQUVAM: Our intention is to submit the data request to the parties who signed the order, and I'm not sure if Mr. Patten has different ideas or thoughts, but then just to lay a foundation verbally.

ACALJ JIBILIAN: Okay. So the actual information will be made available prior?

MR. LOQUVAM: Next week.

ACALJ JIBILIAN: And I haven't seen that proposed form of order, but I assume I'll get it next week, and that's fine.

MR. LOQUVAM: That's right.

ACALJ JIBILIAN: Okay.

MR. RICH: Your Honor, could I just inquire --
ACALJ JIBILIAN: Yes.
MR. RICH: -- to each of the companies?
Do both of you believe you'll be responding to that next week then --
MR. LOQUVAM: Yes.
MR. RICH: -- to those that have signed? APS, yes.
MR. PATTEN: It will be sometime next week.
MR. RICH: Okay.
MR. PATTEN: Not necessarily early in the week, but --
MR. RICH: Sure.
ACALJ JIBILIAN: All right. Any other procedural issues?
MR. POZEFSKY: I guess I just wanted to mention. I don't know if we will file or put a witness on in response to that. I just don't know what our position is. So it's possible we may not do either, because this seems to be between the solar and the companies. So we'll see. I just can't tell at this point.
ACALJ JIBILIAN: Okay. And that's perfectly acceptable, and there are lots of parties to this case who have participated that aren't here today, and if you're listening, then that's something that --

participation in that next phase of this hearing is optional, of course. I appreciate participation, but if that's not something that the parties need to do, then I understand that.

MR. POZEFSKY: Okay.

ACALJ JIBILIAN: Not everyone would be required to put on a witness.

MS. SCOTT: And, Your Honor, the other thing is, I did talk to the parties about if Staff does file a written response rather than presenting a witness, we might want a day or so after the 13th to do that.

ACALJ JIBILIAN: Okay. And we can discuss that at the time.

MS. SCOTT: Okay.

MR. LOQUVAM: And the other sort of issue that we probably don't need to resolve today is just knowing at what point we are going to come and how many witnesses we'll be crossing, and those sort of resources or whether everyone says, you know, we'll just do this in writing and then we can cancel the 13th.

ACALJ JIBILIAN: Sure, any time that the parties want to have a telephonic procedural conference, all you have to do is contact the Hearing Division, and we can set one up.

Okay. Let's get back to the evidentiary portion of the proceeding, and I believe, Mr. Pozefsky, it would be RUCO's turn for cross-examination.

MR. POZEFSKY: Thank you, Your Honor.

CROSS-EXAMINATION

BY MR. POZEFSKY:

Q. Good afternoon, Mr. Beach. How are you?

A. Good afternoon.

Q. I just want to start out by asking you a couple questions in relation to your summary that you made earlier this morning. You talked about a couple rate designs that you believed were acceptable and a couple that weren't of note. The ones that weren't were the fixed charge and the demand charge, and the ones that were would be the minimum bill and the TOU?

A. Yes.

Q. Is that correct?

A. Yes.

Q. When you come up with that, does it matter what the actual charge is, meaning, the minimum bill is acceptable no matter what the minimum bill is?

A. No. I think you would have to -- the magnitude would also be important.

Q. Okay. So if you had a situation where doing this, the minimum bill was actually more than the fixed charge, that may not be appropriate?

A. Yeah. You could do a -- I'm sure you could come up with a scenario where, you know, a really high minimum bill versus a very small fixed charge, and, you know, so the magnitude does matter.

Q. Okay. And you also said a TOU would be acceptable. Can you elaborate a little bit more on that? What type of TOU?

A. Well, there could be a variety of different time-of-use rates. You could have time-of-use rates as they exist today where you typically have an on-peak period and an off-peak period; and sometimes they're differentiated by seasons so you have summer and winter rates as well with a higher on-peak rate and a lower off-peak rate, all volumetric.

There also are what are sometimes described as dynamic pricing time-of-use rates where you might have a relatively high on-peak rate for a limited period of time on a set number of high demand days that are called in advance. It's typically called critical-peak pricing. It's being implemented in California and a number of other states. So that's another type of time-of-use rate that might be considered.

Q. Is there any type of time-of-use rate that's more preferable over another type of time-of-use rate from your standpoint?

A. Well, probably the, you know, the -- I mean, APS is sort of a, has a lot of experience with time-of-use rates and they have a lot of their customers on time-of-use rates. So the simpler two-period rates, all volumetric, those I think have been the most popular, and that would certainly be the place to start.

And for example, California recently in their net metering order, they decided that for customers above the net metering cap in California that installed DG, they would be required to be on a time-of-use rate.

Q. Okay. You also say in your summary that the focus of this value of solar docket should be on exports.

Do you recall that?

A. Yes.

Q. You would agree with me, would you not, that one of the more significant benefits of DG solar is the off-setting the need for additional generation?

A. Yes.

Q. Okay. And those benefits would include or would be related to both the on-site consumption and the exports, correct?

A. Yes, and it's possible that -- you might even have a situation where the value of the exports is lower than the value of the generation that serves on-site load. I mean, you would have to -- you know, it all would depend on the numbers and the various load profiles of the customers.

Q. Okay. And for most DG systems, most of the energy or most of the output is associated with the on-site generation than it is with the exports, correct?

A. It depends -- that depends on the type of customer who is being served, what their load profile is, the orientation of their system. So it's generally, I mean, this is speaking very generally, residential customers tend to export a higher percentage than commercial customers. That's in part because commercial customers tend to peak in the middle of the afternoon when solar output is relatively high.

Also, generally, residential customers tend to install larger systems compared to their usage than commercial so that the size of the system relative to the load also is a key variable in how much is exported.

Q. Would you agree that generally, at least in the summer, the residentials consume more than they export?

A. In Arizona, I would -- I would tend to agree with that, yes.

Q. So there is some value in considering both the output and the exports, correct?

A. Yes.
Q. Okay. Another area I would like to talk to you about is the appropriate testing to be used in determining the value of solar.
On page 20 of your rebuttal, Mr. Beach, you talk about both participant and RIM tests, correct?
A. Yes.
Q. Do you think RIM test is appropriate, an appropriate test to use in the consideration of the value of solar?
A. Yes. Along with the other tests. I would not look at it exclusively.
Q. Okay. So the other test would be the participant cost test, correct?
A. Yes, that's one of the other ones, yes.
Q. And I notice that you talk about it quite a bit. How does that work, that test, sir?
A. For the participant test, on the cost side of the test is the cost of the DG system itself plus integration costs, plus -- well, actually, the principal test for the participants is the cost of the DG system itself. And then the benefits for the participant test are the bill savings for the customer from reducing their utility bill.
Q. How would we know what the cost of the system

is?

A. There are, you know, there are industry surveys out there. I used a survey that Lawrence Berkeley National Lab conducts every, I believe it's every year, of installed solar prices throughout the U.S.

Q. Do you use a lease rate as a system cost?

A. For this, for my study here, I used the customer-owned cost. The costs that were estimated for lease systems were very similar.

Q. Are these system costs what the solar companies report to investors as system price, or are they what they report to the IRS for system price?

A. They're costs that LBL accumulates from a variety of sources. You know, there are some states that, you know, where they have -- that have databases of solar installations, including the costs. And so installers report those costs when they apply. So, you know, that's the kind of information that I think that LBL draws on for their surveys. The report is called Tracking the Sun, and it's widely available if you want to look at the details.

Q. Are there transmission and distribution savings in solar?

A. I believe there are, yes.

Q. Have you identified the transmission lines that

will be avoided if we do DG in Arizona?
A. Again, it's -- my view is that it's not a matter of going out and DG avoiding a specific transmission line. The avoided T&D costs arise because DG will reduce the loading on the T&D system. They'll reduce the peak demand on the system, and the peak demand is correlated with how much the utility has to invest. We do a long-term regression of peak demand versus T&D investments, and it gives you the marginal T&D costs.
So it would be an impossible task to try to identify individual projects that are being deferred because there are many things that reduce the utility's peak demand, not just DG. Energy efficiency, demand response, changes in the economy, et cetera. So, you know, what you need to do is calculate their marginal T&D costs, and associate that with a change in peak demand as a result of DG.
Q. So there's really no way to verify a documented transmission line being avoided because of DG; is that fair?
A. Yeah, occasionally you -- like the report from California that I think has been introduced in this case where the utility will come out and say, yeah, we're not doing these lines because of energy efficiency and rooftop solar. But that's not going to be the norm.

Q. But aren't transmission and distribution upgrades location-specific?

A. To some extent, yes.

Q. So in order to get the benefit of avoiding them, doesn't the PV have to be location-specific?

A. Especially with respect to distribution, yes. But if you assume that, you know, that DG is being installed across a utility service territory, some of it will be installed in areas where the utility really needs distribution capacity, and that will have an immediate savings above average.

And other DG may be installed in areas that have excess capacity and may not produce savings for a number of years. But on average, there will be, you know, a cost savings. It will be greater in some areas and less in others.

Q. So is there any way that we can be sure that PV systems are specific to a location to avoid a transmission or a distribution line in that location?

A. Well, that's kind of the cutting edge of DG. California and New York are working on programs to do exactly that, to try to get DG sited in areas where the need is most immediate. But -- and I think that perhaps some of the things that APS is doing in Arizona will help, you know, indicate how DG combined with smart inverters and storage can be targeted to areas where they're most needed.

Q. So in the meantime, how do we place a value on this in our consideration of the value of solar?

A. I think in the short-run you have to do what I did in my benefit/cost study which is look at the correlation between T&D investments and peak demand. And that is, you know, that's kind of an average to top-down type approach; but it's one that utilities often use to calculate their marginal T&D costs. And it gives you a, you know, a general relationship between changes in peak demand and changes in T&D costs.

Q. Mr. Beach, in the world of electricity, can you tell me somewhere else where ratepayers actually pay value?

A. I'm not sure what you mean by value.

Q. Well, the actual value that we're trying to attribute that the solar utility -- excuse me, the solar industry is claiming, the actual value because of all the benefits versus the costs. Is there any other area in electricity where ratepayers actually pay --

A. Sure. You know, qualifying facilities under PURPA are paid avoided cost prices, and I think you would describe -- that's similar to what we do, we're trying to do here. That represents the costs that are avoided by these resources being in place; and because those resources are in place, you don't have to do something else, and that's -- ratepayers certainly pay for those costs.

Q. Can value be subjective?

A. Well, you know, there's -- as you get into more and more benefits that are more difficult to quantify, you know, it becomes more subjective. But I think that for most of the categories of costs here, there are pretty well defined ways to estimate them.

Q. If solar continues to decline in price, and let's say it costs 3 cents per kilowatt but the value is 10 cents per kilowatt, should ratepayers pay the 10 cents per kilowatt?

A. I don't -- what kind of solar are you talking about?

Q. DG.

A. DG. I mean, if solar costs, DG solar costs only 3 cents a kilowatt hour, then I would agree that, you know, if the rate is 12 cents, then net metering, you know, would be out of balance. You would be -- the costs would be 3 cents and the bill savings and lost revenues would be 12 cents. And so from the participant test, the participant would be getting a great deal and the nonparticipating customer would not be getting a great deal. And so that's certainly a situation in which there would need to be something besides net metering.

Q. You would agree that we must, regardless what the numbers come out, we must have a common sense approach to this, correct?

A. It's always a good idea.

Q. If the ratepayer can get community solar in the distribution system, let's say for 6 cents per kilowatt, should the ratepayer pay 12 cents for residential rooftop PV?

A. Is your hypothetical that the cost of the community solar facility itself is 6 cents?

Q. Yes.

A. Yeah, the thing about that is that that power still needs to be moved over the utility's T&D system to get to the community solar subscribers, and --

Q. Let me -- I'm sorry, go ahead. I don't want to cut you off.

A. I doubt the utility would agree to move that power, to wheel that power over its system for free. So my guess would be that you would have 6-cent community solar and the utility charge 6 cents for T&D, and the end cost to the community solar would be 12 cents, just like the DG.

Q. Okay. But let's say the end cost was 6 cents or 8 cents, for that matter. Should the ratepayer pay 12 cents, hypothetically, if that's what our residential rooftop PV is, should the ratepayer pay that?

A. So your hypothetical is that community solar costs are less than the full retail rate?

Q. Yes.

A. Well, you know, I am not aware of anywhere where that has turned out to be the case. The community solar projects that I'm aware of, they're not -- there are situations where the cost to the customer is usually at or somewhat above the retail rate. If you could actually have a utility who would agree to a community solar arrangement that actually saves customers 4 cents a kilowatt hour rather than charging them a premium, you know, first of all, I think that would be pretty heavily subscribed by customers. And whether it would be a benchmark for net metering, you know, if you actually could have that arrangement in place, my guess is that the cost of DG solar would be less than 12 cents.

Q. Do you agree that it should be less than 12 cents if that were the arrangement?

A. You know, I think I'd need to know what the cost difference is between DG solar and community solar. Your hypothetical seems to posit a really big difference between those two kinds of projects, which I'm not sure that that would be the case.

Q. Okay. So it's your testimony that the size of the difference is important or necessary in order for you to opine on that, right?

A. Probably, yes.

MR. POZEFSKY: Okay. I think that's all I have. Thank you, Your Honor.

Thank you, Mr. Beach.

ACALJ JIBILIAN: Ms. Scott?

CROSS-EXAMINATION

BY MS. SCOTT:

Q. Good afternoon, Mr. Beach.

A. Good afternoon.

Q. So I wanted to ask you with respect to the cost of service studies. APS filed its cost of service study in this docket, and I believe TEP and UNSE indicated that theirs were in their rate case, but that's what they would recommend.

But your position is that those cost of service studies are not appropriate to determine cost shifts?

A. Yes.

Q. And can you tell me why?

A. Well, I think that the -- generally cost of service studies just focus on an historical test year. They just look at one year of the utility's costs; whereas, what we're talking about here are long-term generating resources that will be around for 20 years. And you don't capture all of the benefits of these resources by just looking at a single test year. I think that's probably the most important reason.

The second reason is that cost of service studies use embedded costs. They don't use marginal costs. Marginal cost is the change in costs, you know, with a change in demand. I think you really need to look at marginal costs to assess the benefits of DG.

Q. You mentioned earlier that, I think it was California has a full decoupling, full revenue decoupling in place, correct?

A. Yes.

Q. How do they determine the cost shift in that state?

A. They have done a series of long-term benefit/ cost studies of net metering. The first one was done in 2010. Then they did another one in 2013, and then most recently, they developed this public tool model which was used by the parties in the net metering 2.0 proceeding in California. So every few years they've done a long-term benefit/cost study such as what I've recommended to look at the cost shifts associated with net metering.

Q. So they don't look at decoupling in terms -- in the context of a rate case?

A. No. You know, I have to say rates have been decoupled in California for about 30 years. So they just don't -- they don't look at decoupling issues in California at all. It's just the way it's done.

Q. So that situation is much different than what we're looking at here then, correct?

A. Well, yeah. In Arizona you have the potential for DG that's installed between rate bases -- excuse me, installed between rate cases to affect the utility's earnings, so you have things like the LFCR process which is kind of a partial decoupling to address that issue.

Q. I just want to ask one more follow-up question on this.

Given the situation in Arizona where we do look at it within the confines of a rate case, don't you believe that the cost of service test would be an appropriate means to determine the cost shift?

A. Not for a long-term resource, because you just can't capture all the benefits and costs by looking at one year of costs and savings. Many of the savings that these technologies are going to produce may not materialize, especially if it's an historic test year that has already happened. You're just not going to capture them.

Q. Okay. So your recommendation would be to look at avoided costs, as many parties are, most parties are in agreement on that, to look at the avoided costs, I guess as set forth in the PURPA model; is that correct?

A. Yes, it's basically following the model that was first kind of pioneered by PURPA but then has been extended to be used, you know, for other demand-side resources for energy efficiency and demand response.

Q. Do you know if under PURPA there is a requirement that short-term avoided costs be used in that computation?

A. It doesn't have to be short-run avoided costs, is my understanding.

Q. Okay. And your recommendation would be to use long-term avoided costs, correct?

A. Yes.

Q. And under that scenario, you're advocating that the Commission look at the useful life of a solar DG system, correct?

A. Yes.

Q. And you have a wide range there, however. You have from 20 to 30 years. I've seen 20 years, but I haven't seen the 30 years before. Is there a reason why you've got such a wide range there?

A. Well, most of the studies that we've done have been 20 years. However, I just did testimony in an IRP proceeding in Georgia where they did 30 years, because the utility did all of its IRP costs on a 30-year basis. So that's what I used. But I generally would support 20 years.

Q. Well, I want to just follow up on the last answer that you gave.

Would your recommendation then be to use the time span used in the IRP process in looking at long-term costs?

A. My recommendation is to use the life of the DG facility, which could be -- you know, some states have like 10-year IRP forecasts. I think that's too short. I think you need to look at it for more than 10 years. I would recommend 20 years as a minimum.

Q. Do you know what the IRP looks at in Arizona?

A. I think it's -- my recollection is 15 years or something on that order.

Q. Okay. I think that's correct.

But the 15 years might be an alternative, in your opinion?

A. You know, I would prefer 20. Maybe if we were negotiating a comprehensive settlement or something, but, you know, I have a 13-year-old solar system on my house that is running beautifully, and I'm sure it's going to last at least 20 years. So these technologies are warrantied for 20 to 25 years. So that's what I would prefer, the term that I would prefer.

Q. So somewhere in your testimony you state that in Arizona the right balance exists now, correct?

A. Yes.

Q. And so by that, I assume you mean that a retail rate should remain in effect for exports?

A. Yes.

Q. And that the two-part rate should be maintained?

A. Yes.

Q. If there were changes made by the Commission as a result of this proceeding, and by that I mean if there's a methodology adopted and it would lead to a different result, would you support that result?

A. You know, I guess I would have to see what the results of that are. I mean, you know, I can tell you that I -- you know, the Commission in Nevada chose a different methodology from what we recommended, and I don't support that outcome. I mean it has pretty much decimated the industry there, and the Commission did not look at the impact of their decision on participating solar customers. And that's what happened.

Q. Now, they had a subsequent decision, did they not, which spread the impact over 12 years?

A. Yes, that's correct. And, you know, I know that there are, there are still active discussions on that issue going on in Nevada.

Q. I wanted to talk to you a little bit about your comparisons between grid scale and rooftop solar.

I understand your characterization when you say that it's not quite an apples-to-apples comparison. And you suggest in your testimony that in order to get an apples-to-apples comparison, I believe, that you would add in, that you would need to add in the long-run marginal costs associated with this at both transmission and distribution?

A. Yes.

Q. And have you done that calculation?

A. I don't -- no, not explicitly.

Q. Is that a difficult calculation to do?

A. You know, I have done it in other contexts, so no, it's not particularly difficult. It takes a little bit of effort, but it's not particularly difficult.

Q. I wanted to ask you, you talk about a lot of different states in your testimony, but I didn't see any reference at all to Utah. Are you familiar with what the Utah Commission did?

A. I have not -- only very generally. I have not been involved in DG issues in Utah.

Q. With respect to the general information you have, what is your impression of that state's most recent order?

A. Well, my understanding of it was they have a methodology that has cost of service studies with and without DG, and then I also understood that they were also looking at long-run avoided costs for long-run benefits. But it sounds like kind of an effort to make everybody happy. But I am not aware of the results of whether they've done their study or what the results are.

Q. I think that would be a great result to make everyone happy.

I wanted to ask you, you've set out four different tests in your testimony; is that correct?

A. Yes.

Q. You've got the RIM test, you've got the participant test, the societal test, and then, let's see here, the TRC?

A. Yes.

Q. Could you just explain each of those for us very quickly?

A. Sure. And there is a, if you want, it's kind of a guide to the tests. Table 1 in my direct testimony shows which costs and which benefits are included in each of the tests.

So the participant test looks at the perspective of the DG customer, and in that test, the costs are the costs of installing DG on the customer's premises. The benefits for the customer are federal tax benefits and the bill savings that they get from reducing their utility bill. So that's the participant test.

The RIM test -- RIM stands for Ratepayer Impact Measure, and that looks at the perspective of nonparticipating ratepayers. So in that test, the costs are the utility's lost revenues, which are equal -- the same thing as the bill savings. So what is a cost in the RIM test is a benefit in the participant test. And then in the RIM test the benefits are the utility's avoided costs. So the nonparticipating customers have to pay the credits given to participating customers, but the benefit they get is over time. The utility lowers its costs. They use less fuel. They build fewer power plants. They put in less T&D infrastructure. You can also include as a cost in the RIM test integration costs and program administration costs.

And then the total resource cost test, that looks at, you know, is this a cost-effective resource to the system as a whole? In that test, the costs are the capital and O&M costs of the DG, how much does it cost society to build DG. And the benefits are the benefits, the avoided cost benefits to the utility from the utility not having to build that resource. And again, on the cost side, you can include the program administration and integration costs on that test.

Now, the societal test is just a variation of the TRC test where you include societal benefits as well.

Q. Okay. Thank you for that.

So you're advocating that the Commission look at all of these tests?

A. Yes, and I think that it's important to have all three of those perspectives, especially to balance the first two, the perspective of the participants and the nonparticipants.

Q. Okay. And I wanted to ask you, do all the other states use these tests?

A. I think states differ in the weight that they give to the various tests. I think most demand-side programs, most states do look at -- they tend to look at, especially look at the TRC and the RIM tests, and then you have to look at the participant test to make sure it's a good deal, that you're going to get people to sign up for your program. So I think most states look at all three of these tests. Some of them put different weights on -- some of them weight the TRC test more and the RIM test less. Others rate the RIM test more and the TRC test less. That's kind of a state by state.

Q. Are there any states in looking at the value of distributed generation that don't utilize these tests?

A. Well, you know, it's somewhat amazing to realize this, but Hawaii, which has, of course, the highest penetration by far, they have not really looked at -- they haven't really looked at the benefits and costs yet, despite their penetration. I think they are going to in the next phase of their DG rulemaking, but that's a state that hasn't looked at it from this framework. But lots of states have.

Q. Most do then?

A. Yes.

Q. Okay. You had a discussion earlier that value of solar studies are not used to set rates, correct?

A. Yes.

Q. And I want to ask you about that because you quote from Mr. Albert's testimony in your rebuttal. And you quote him as saying, for example, the Commission can consider the VOS in determining the amount paid to customers who export energy to the grid from their rooftop solar system. Isn't that setting a rate?

A. I'm sorry, where are you referring to?

Q. Look at page 4 on your rebuttal, in your rebuttal. Lines 7 through 13.

A. Well, that's Mr. Albert's testimony. It's not mine.

Q. Okay. And I wanted to ask you about the Minnesota value of solar tariff.

Does that tariff contain rates?

A. Yes, that is -- my understanding of the Minnesota value of solar tariff is it would be a buy-all/sell-all rate, so you would receive the value of solar for all of your output. It's also my understanding that none of the utilities in Minnesota have yet adopted that, so it's not actually in effect.

Q. Okay. And then, what were the results of your avoided cost calculations?

A. I think if you look at my study and you look at table 1 where it says direct benefits, and then it has south-facing, west-facing and average, those would be the avoided cost benefits. So 18.7 cents for residential and 20.7 for commercial.

Q. And that's under a long-term analysis, correct?

A. Yes. Those are 20-year levelized numbers.
Q. 20 years. In response to Commissioner Little's questions, you talk about smart inverters and storage, and you talk about the benefits associated with those.
A. Yes.
Q. How would you factor in those benefits into an avoided cost determination?
A. Smart inverters have the potential to enable solar to provide additional benefits on the distribution system such as voltage support and perhaps even some measure of dispatchability. Storage can be a major game changer in terms of the value of solar because it can enable the maximum output of solar to be -- you can actually shift the output profile of solar to the exact period when you want it using storage, by using solar to fill the storage and then having the storage discharge at the period that's most valuable to the utility.
So, whereas solar alone may have a capacity value that's only, you know, 30 to 50 percent of its nameplate, if you combine solar with a relatively small amount of storage, you can dramatically increase the capacity value of solar to, you know, potentially to its full nameplate.
Q. Okay. So it sounds to me like if these technologies start becoming more commonplace and

incorporated into the network here, that that will automatically, in your opinion, be taken into account in the avoided cost determination as it's now set out; is that correct?

A. Yes. It would be -- as technologies develop, such as storage and smart inverters, then those benefits could be incorporated into this methodology.

Q. And I just want to follow up, too. You had made the statement, I believe Mr. Loquvam asked you about the use of long-term forecasts to set rates, and you're saying you're not setting rates here. Could you elaborate on that?

A. Well, again, we're not setting rates. We're just looking at the long-term benefits and costs of these technologies, and, you know, net metering and rate design affect the balance of benefits and costs.

Q. Okay.

A. And so if you think that the balance is not in the right place and it needs to be adjusted, then one way to do that is to, is through rate design. I'm not -- this is not like setting utility rates where you have to set rates to exactly cover the cost. What we're trying to do here is achieve a balance of benefits and costs in the eyes of the regulator, between those who install DG and remaining ratepayers. And one way to adjust that balance is through rate design.

Q. Okay. So the avoided cost determinations that you referred to earlier, the 18.7 and the 20.7 for commercial, 18.7 for residential, you're not recommending that the Commission adopt those for the export rate, but just consider that along with all the other factors, correct?

A. That's correct.

Q. Okay.

MS. SCOTT: Your Honor, I'm just going to page through here to see what else I have left.

BY MS. SCOTT:

Q. On page 6 of your rebuttal testimony --

A. Okay.

Q. -- I thought it was amazing that you and Mr. Brown agreed on something. You state, "I agree with Mr. Brown that it is preferable to use markets and market prices to establish the benefits of DG."

I found your discussion then about this point interesting, and that's over on page 7, lines 14 through 18. Can you talk a little bit about the challenges in Arizona with respect to that.

A. Yes. You know, utilities in the U.S. are organized and regulated in different ways. And energy markets in the U.S. are organized and regulated in different ways. There are some regions in the country that have, that have kind of deregulated wholesale markets that have ISOs who run transmission grid, that have day-ahead energy markets. And in those markets, a lot of data is available on hourly energy prices. Data is available on transmission congestion. Data is available in some of them on capacity prices. Some of them have capacity markets that have visible transparent prices. And that kind of information is of significant assistance in doing these studies.

So, you know, we've done studies in California which has, you know, a day-ahead market but it does not have a capacity market. We've done studies in New England that has both capacity markets and day-ahead energy markets. We've done studies in PJM that probably is the most sophisticated of all of them. And the more deregulated markets have more data available, so it tends to make the studies a little easier to do, especially on an hourly type basis. But, you know, we've also done them in places like Arizona that still have vertically integrated utilities where it's a little more difficult to get the data. But the same principles and the same avoided costs are being studied in all these, in these different markets. It's just a matter of -- you know, some of them the data is a little more readily available.

Q. Okay. I wanted to ask you with respect to the export rate. Let's say that your avoided cost methodology produced an export rate for residential of, oh, let's say 11 cents. Would you advocate that the Commission adopt that export rate?

A. Would that be 11 cents, a levelized rate for 20 years? Is that the idea? My methodology does produce, you know, a levelized 20-year rate.

Q. Okay. Well, yes, let's assume that we've used the long-term avoided cost methodology and that the levelized, it's levelized so it produces an 11-cent rate.

A. And is your question whether that would be, result in an equitable balance between like participating and nonparticipating ratepayers?

Q. Yes.

A. You know, if we felt the methodology was robust and that it was accurately capturing the costs, then, you know, I would recommend to my client that that might be a reasonable rate.

Q. Okay. You suggest to the Commission, as do a lot of people, including Staff, that the Commission in this proceeding focus on the export rate, correct?

A. Yes, although, you know, again, I think it's a lot easier to calculate the all-output rate. So that issue has to be weighed as well.

Q. And in your testimony, I think you do state that there are some benefits related with on-site production. How would you incorporate those into this methodology?

A. You said that there are some benefits associated with on-site production?

Q. I thought that was your testimony.

A. Well, most of the benefits of the power being used on-site are also realized by, even with the power that's exported, because it's literally used by the neighbors. So there isn't a huge difference between the benefits for whether the power is being used by yourself or by your neighbors.

Q. And then you also talk about incentives, the use of upfront incentives. And one of the uses you suggest is to encourage and incentivize west-facing systems, correct?

A. Yes.

Q. Are you also proposing incentives for any other similar type of --

A. Well, I think I -- I believe I mentioned in my rebuttal incentives for storage that, you know, for example, some states are incentivizing distributed storage as a way to -- in the same way that utilities in many states incentivized solar, you know, a few years ago to get it off the ground. States are incentivizing storage in order to start to bring that technology to scale, because it potentially has, you know, enormous benefits, including used at the distributed level.

So I would certainly think it would be very positive if Arizona helped in that effort and incentivized storage.

Q. And I think -- have you read Mr. Solganick's testimony?

A. I know I read his direct testimony. I'm not sure I read his rebuttal.

Q. I think it was in his direct, he suggested perhaps using incentives to get DG rooftop sited in a particular area where it may have benefits for the distribution feeder.

Do you recall that?

A. Yes, and I would agree that that would be a good idea. I would support that.

Q. Now, in your opinion then -- because you use this balancing test, also. In your opinion, then, would you factor all of these incentives into the equation in determining the right mix?

A. Well, I think, you know, for example, my study calculates a higher value for west-facing systems, of, you know, several cents a kilowatt hour. So you could look at that difference in the value, and you could use a portion of that difference in value to construct an incentive for people to site their solar facing west.

Q. But I think my point was, you talk a lot about the rate design. You talk about incentives. You talk about the export rate, the avoided cost, and I read your testimony to say that you can adjust these in different ways, and you can create the right balance. You don't have -- it's not one correct answer; is that correct?

A. That's correct. And I think I've kind of emphasized in my testimony today that one way to adjust the balance is through rate design. But you also can adjust the balance through various kinds of incentives. And if you look at the study that we did in 2013 in Arizona, back in that time frame, there still were some incentives for solar, and those were factored into that study as a cost because those are a cost to ratepayers for paying those incentives. So if there would be an incentive for, you know, west-facing systems, then that should be kind of included in the calculation as a cost.

Q. I think that might be all I have. That is all I have. Thank you, Mr. Beach.

A. Thank you very much.

ACALJ JIBILIAN: Mr. Rich, do you have redirect?

MR. RICH: Your Honor, just a couple questions real quick. And then we'll get you out of here, Mr. Beach.

REDIRECT EXAMINATION

BY MR. RICH:

Q. You were just asked about, a hypothetical finding that if your methodology was run and an 11-cent output were to come out of it, and in that hypothetical I think it's presumed that 11 cents is just below the retail rate. The question was, would you support the Commission adopting that rate?

Would you agree that if the Commission should find 11 cents or some other number below retail comes out of that methodology, would you agree that it has options besides adjusting the net metering rate, and that it could look at rate design if it wanted to preserve the simplicity of net metering but deal with some shortfall?

A. Yes. I think that's an important consideration, because, you know, the real value of net metering and why it's been such a successful policy is the customers understand it, and they understand that, you know, they pay the retail rate when the meter runs forward, and they get credited the retail rate when the meter runs backwards. And so, you know, I think that the Commission probably should look first at the kind of changes I've recommended to rate design before it takes the next step to create a completely separate export rate so that customers then are being compensated differently for imports versus being credited for exports.

Q. Okay. Thank you. And I wanted to clear up much earlier today, at this point, you were asked about the Nevada, I think it was APS Exhibit 11 which was an order out of Nevada that was from sometime in mid February.

Do you recall that line of questioning?

A. Yes.

Q. And I just wanted to clarify, that was an order, APS Exhibit 11 is an order that dealt with a discrete issue within the Nevada discussion, correct? It was with regard to the grandfathering issue only?

A. Yes. The original order on the rates and net metering came out, I believe, on December 23 of 2015.

Q. Okay. So when you were examining the job losses that you referred to, you were not looking at the job losses in the few days between that February order and your February testimony in this case, but instead you were looking at the job losses that flowed from the December decision, correct?

A. Yes. Those were job losses that -- I filed that subsequent testimony, I think, on February 5th or 1st. Actually, I filed direct on the 1st and rebuttal on the 5th. And so the job losses were what had been documented basically during the month of -- the end of December and during January.

Q. Just to clarify, there has been a lot of talk of forecasting, but you would agree that the utilities before they decide to acquire a resource or construct a gas-fired power plant, for example, use forecasting to make that decision, correct?

A. Yes.

Q. Okay. And those forecasts are made, yet future occurrences, either slower growth of the service territory, negative growth in the service territory, price of gas and other issues can impact the reliability of those forecasts?

A. Yes. And so, you know, the conditions under which those decisions to build that plant were made can change in the future. And sometimes that's a benefit to ratepayers. Sometimes it's a cost.

Q. And just one final clarifying question.

Would you agree that there's nothing unique about the way that utilities treat reduced kilowatt hour sales arising from the use of distributed generation versus the way that they treat reduced kilowatt hour sales arising from any number of energy efficiency devices or strategies or just a customer who is more careful in using their energy or otherwise reduces their energy consumption?

A. No, there's really no difference. You know, I know that in Arizona, the LFCR mechanism deals with both DG and -- loss in sales due to both energy efficiency and demand response as well as DG. And I think those sales reductions are basically treated the same in that process.

Q. Okay. I have no other questions. Thank you very much.

ACALJ JIBILIAN: Is there any recross based on that redirect?

MR. LOQUVAM: Yes, Your Honor.

ACALJ JIBILIAN: Mr. Loquvam.

RECROSS-EXAMINATION

BY MR. LOQUVAM:

Q. Mr. Rich just discussed the retail rate credit and the 11-cent issue. And we've all banged our heads at one point or another individually and collectively about possibilities for middle ground.

Would you support or recommend to your client or do you think TASC would support, if you know, a retail rate credit that is not net metering but equaled the retail rate? So if, for instance, APS's average retail rate is about 12 and a half cents per kWh. So instead of a 1 for 1 kWh, it's just a 12.5-cent credit on the bill and the customers see the exact same monetary impact.

A. I'm not sure I understand how that's different than net metering.

Q. It's just not net metering, but it's just the full retail rate. Or maybe a 12-cent or a slight reduction. I mean, is there any wiggle room? At what point do we start moving to the middle?

A. I would have to understand how that's different than net metering. I mean, if you're getting, if you get a 12-cent credit under net metering and you would get a 12-cent credit under your approach that's not called net metering, how are they different?

Q. So, in other words, you would support it or think --

A. I mean, you know, at the end of the day, I believe that what the solar industry wants to do is have a reasonable chance to grow, you know, and to market its product; and net metering has been very successful, as I said, because the customers understand it and it's simple. But it is, you know, it is a rough justice kind of approach, and you have to do studies like this in order to make sure that it still is the right approach.

Q. Then on the second point in discussing forecast change, wouldn't it be better for customers and protect nonDG customers more if whatever export rate is established was trued-up or recalculated annually based on the new forecast?

MR. RICH: Your Honor, I'm going to object. I think this goes beyond the scope of the redirect.

MR. LOQUVAM: Your Honor, he's talking about forecast changing, and I'm trying to find solutions.

ACALJ JIBILIAN: Can you repeat the question, please?

MR. LOQUVAM: I'm happy to.

ACALJ JIBILIAN: Yeah, please do.

BY MR. LOQUVAM:

Q. I mean, it's a question about whether in light of forecasts changing it would make sense to instead have true-ups every year or recalculate forecasts every year as circumstances change.

ACALJ JIBILIAN: I'll allow that.

THE WITNESS: You know, generally, I think that, you know, this is a -- this certainly is a dynamic market, and there are changes in solar costs; there are changes in utility rates; there are changes in avoided costs. And so, you know, this balance between participating and nonparticipating ratepayers will change over time, and so I do agree that it needs to be looked at periodically. I'm not sure I would do it every year, but every rate case, something like that.

MR. LOQUVAM: Nothing further, Your Honor.

ACALJ JIBILIAN: Is there anything further, Mr. Rich?

MR. RICH: No, thank you, Your Honor.

ACALJ JIBILIAN: Thank you for your testimony, sir. You're excused.

You can just leave everything there.

THE WITNESS: Okay.

ACALJ JIBILIAN: Are you ready to call your next witness, Mr. Rich?

MR. RICH: Yes, Your Honor. TASC calls Mr. William A. Monsen to the stand.

WILLIAM A. MONSEN,

called as a witness on behalf of TASC, having been first duly sworn by the Certified Reporter to speak the truth and nothing but the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. RICH:

Q. Good afternoon, Mr. Monsen. Thanks for being here and hanging around.

A. Good afternoon.

Q. Make sure your mike is on and you get settled there.

A. Okay.

Q. All right. First of all, can you state your name and your place of employment for the record?

A. William A. Monsen. MRW & Associates, LLC.

Q. Who are you here to testify on behalf of today?

A. I am testifying on behalf of The Alliance for Solar Choice.

Q. Great. I've put in front of you two documents labeled TASC Exhibit 29 and TASC Exhibit 30.

Would you agree that TASC Exhibit 29 is a copy of your rebuttal testimony submitted in this docket?

A. Yes.

Q. Let me ask you then, do you also -- can you identify TASC Exhibit 30 as a Notice of Errata that was filed on May 5, including some corrections to your testimony?

A. Yes. That's what it is.

Q. Okay. With regard to TASC-29, your rebuttal testimony, was that prepared by you or at your direction?

A. Yes, it was.

Q. If I asked you those same questions that appear in that testimony today, would you answer them the same way here under oath?

A. Yes.

Q. And I understand in preparing for today that you have a couple of corrections to make to that; is that accurate?

A. Yes, I do.

Q. Okay. Why don't you take us through those corrections briefly, and then we can discuss the errata filing and go from there.

A. Okay. On page 2 -- oh, I'm sorry. Yes. Page 2, line 12, it says, "Used in those costs." It should be "Used in the cost." None of these are very big, by the way.

Q. I would ask if you, in that exhibit copy, if you can just line through and correct.

A. Okay. On page 4, line 1, insert the word "not" between the words "has" and "met".

ACALJ JIBILIAN: What is the page and line reference, please?

THE WITNESS: Oh, it's -- okay, page 3, line 32.

I think somehow mine is mispaginated.

Where it says toward the end of the line, "APS has met its burden," it should be, "APS has not met its burden."

On page 18 -- I'm sorry, page 18, line 18, after the word "APS's", you should insert the word "method."

On page 22, line 1, you should insert the word "not" at the beginning of that line, so it should read now "not be reasonable."

On page 25, footnote 44, line 3, insert the word "supplemental" at the beginning of that line. So it should now read "APS supplemental response."

And in that same footnote, going to insert after the 1.15, you're going to insert the phrase "and APS response to TASC data request 2.1B."

Those are all the changes to Exhibit 29.

BY MR. RICH:

Q. And then with regard to Exhibit 30 which is the Notice of Errata, including pages inserted and corrections made to exhibits that were corrected -- I'm sorry, to exhibits that were attached to your testimony, was this document prepared at -- I believe you testified to this. Was this document prepared at your direction or by you?

A. Yes, it was.

Q. And each of these changes that are reflected on the first page of the document entitled Errata Corrections to Direct Testimony of William A. Monsen, each of those are included in the following pages; is that correct?

A. Yes.

Q. Okay. And it's your testimony that the pages that follow within this Notice of Errata is a complete copy of the exhibits that should be attached to your testimony in the way that you intended them to be presented and adopted as your testimony today?

A. Yes.

MR. RICH: Okay. And with that, Your Honor, I would move the admission of TASC Exhibit 29 and TASC Exhibit 30.

ACALJ JIBILIAN: Is there any objection?

TASC-29 and TASC-30 are admitted.

(Exhibit TASC-29 and Exhibit TASC-30 were admitted into evidence.)

MR. RICH: Thank you, Your Honor.

BY MR. RICH:

Q. So now we can get down to business, Mr. Monsen.

Give us a brief summary of your testimony and respond, please, to anything that you've heard during the course of the hearing that you think is appropriate to respond to.

A. Okay. Thank you.

My testimony in this proceeding addresses four main questions that I'm going to walk through them in order.

The first question is, should the Commission make findings and conclusions in this docket related to the reasonableness of the assumptions or conclusions drawn from the cost of service studies submitted by the utilities? So that's the first question. And my response to that is, while a cost of service study is useful for rate-setting purposes, these models are very complex and very data-intensive, and need very careful scrutiny in order to fully analyze and test the underlying assumptions and modeling.

In this proceeding such scrutiny was not possible. Thus, the Commission should not rule on these models or their results in this docket. Why do I believe that this is not the appropriate venue to examine the reasonableness of these very complex and data-intensive models? The main reason, as discussed yesterday by Vote Solar's witness, Briana Kobor, is the model that APS provided to parties in response to discovery was not a "working model," despite the fact that APS labeled the model as such. It is not possible to make changes in other models that APS clearly used to develop inputs for its cost of service model and to see the impact of those changes in its cost of service study.

For example, I had originally hoped to analyze the cost of service of solar DG customers using the delivered loads supplied by APS. However, this was not possible, given the lack of functionality in the so-called working cost of service model.

Aside from the failure of APS to provide parties with a model with which to analyze alternative assumptions associated with calculation of the cost of service, this docket is a special docket in which it is possible that other parties that are interested in cost of service issues are not actively participating. To adopt decisions regarding the reasonableness of cost of service assumptions and modeling approaches could potentially harm those parties.

For those reasons, I recommend that the Commission note potential concerns with the cost of service modeling, but not make findings or conclusions regarding the validity of the modeling submitted in this docket.

The second question that I asked is, is the cost of service study -- is a cost of service study even the appropriate tool for the determination of the value of solar? And the short answer is no. A cost of service study is not an appropriate tool for determining the value of long-term resources such as solar DG.

Why do I believe this? The most telling reason is that I am unaware of any utility using a cost of service model to determine the reasonableness of decisions regarding the acquisition of long-term resources.

I worked for an investor-owned utility for eight years and worked closely with the generation planners in that company. Cost of service models were not used to decide about the reasonableness of resource options.

While at the utility, I was involved in consideration and evaluation of demand-side management resources such as energy efficiency and load management programs. We did not use cost of service models to analyze the reasonableness of pursuing those resources either.

Since becoming a consultant, I have participated in numerous resource planning dockets, and have never seen a cost of service model used to evaluate resource plans. As a result, it is hard for me to believe or hard for me to understand why APS believes that a cost of service model can provide insights into the reasonableness of long-term resource decisions, which is exactly what solar DG projects are.

Why are cost of service models the wrong tool for determining the value of a long-run resource? As Mr. Beach just indicated, they're backwards-looking. They look at the world as it exists in the past at this point in time, not as a utility expects it to be in the future.

Second, even if the cost of service model was looking at a prospective test year, it still only looks at a single year. Such an approach might make sense if the future were to look exactly like the present. But as we all know, this is not the case. Loads grow. Fuel prices change. Technology evolves. An IRP addresses these changing relationships. A cost of service model does not.

For these reasons I recommend that the Commission give no weight to the cost of service models as tools for determining the value of solar.

The third question is, did APS meet its burden of proof regarding its assertions that solar DG customers have load shapes that are so different from other customers that solar DG should be assigned to a new customer class.

APS contends that one reason to establish a new customer class for solar DG customers is because they have different load shapes. However, APS has other sets of customers that have different load shapes; but to my knowledge, APS has made no effort to separate those customers into separate customer classes. These include winter visitors and customers that have either smart or setback thermostats.

APS tried to claim that winter visitors are very similar to their other customers, and that they in fact pay more than their cost of service. This is not reasonable.

I wasn't a witness in the UNS general rate case, but I understand that UNS believes that their winter visitors significantly underpay relative to their cost of service.

I'm also aware that other utilities have established special rates for seasonal customers. I'm not trying to pick a fight with winter visitors. However, the fact that winter visitors have loads that peak in the winter, not in the summer. They have very low annual load factors, primarily because they consume very little power in the summer months. Despite having peak loads in the nonsummer months, these customers live in homes and residences just like other customers that live here all year-round, meaning that interconnection facilities for these homes are the same as other types of homes which means that they cost the same to interconnect. All these things tend to point to customers that might pay less than their full cost of service.

How did APS reach the conclusion that winter visitors pay more than their full cost of service? APS assumed that the costs allocated to these customers for distribution facilities are based on their loads in the summer months, even though these customers have maximum noncoincident peak demands and some have maximum demands that occur in winter months. Thus, APS's assertion that winter visitors pay more than their full cost of service is incorrect.

Another example of a customer group that has very different load shapes than the residential customer class as a whole are customers that somehow reduce their air conditioning usage during the middle of summer days. These customers could be customers that turn up the set point on their thermostats before they leave their house for the day. They could have programmable thermostats that they program to increase the set point during the day. They could even have smart thermostats which could take a signal from the Internet or even from APS to increase the thermostat set point.

In any case, when the thermostat set point is increased on a hot day, these customers' air conditioning loads drop until such time as the occupant returns to the home. This results in a dip in usage during the middle of the day which is not consistent with the average load shape of residential customers during those days.

I had hoped to obtain information about the load shapes for APS's customers with this and other load control technologies to show the Commission how these APS customers' loads differ from the average. However, APS was unable to provide actual load data for these customers.

Thus, I present evidence in my testimony that show how customers' loads change as a result of new behind-the-meter technologies based on studies from other regions.

Like with the winter visitors, APS is not proposing to create new customer classes for this group of customers. Based on this selective application of whether customers with different load shapes should be in different customer classes, it appears that APS's proposal to establish new customer classes for solar DG customers is discriminatory.

The final question that I asked is, are there assumptions used in the APS cost of service study that are questionable, calling into question the results of the study itself? Even though I believe that this is not the proper venue to vet cost of service models, I felt that it was important for the Commission to see that a number of assumptions used by APS in its modeling were questionable, and when corrected, give significantly different answers regarding the net costs of service for DG customers.

First, as pointed out by Vote Solar witness Kobor, APS uses a DG customer's gross load or site load that is the electric used by customers, not the electricity delivered by APS as a billing determinant in its cost of service study. This is different than how APS models other customers such as customers that install energy efficiency, demand response, smart thermostats and other load-modifying technologies.

For all of APS's other customers, APS uses the delivered load as the basis for determining cost of service. If APS used the delivered load for solar customers -- I'm sorry, APS did not do this. Realizing that such an approach is unreasonable, APS calculates some value adders to account for the costs that solar DG customers avoid on the APS generation system. However, these value adders only address a portion of the costs that solar DG customers avoid. APS assumes that there are no avoided distribution-related costs resulting from the installation of distributed generation, and it doesn't even try to estimate these values. This is despite evidence from other utilities that energy efficiency and distributed generation have resulted in the ability of utilities to avoid significant transmission-related expenditures. Mr. Beach referred to Pacific Gas & Electric's recognition that they avoided approximately $200 million of subtransmission-related expenses.

Even more troubling, it appears that APS does not assign a generation demand credit to solar DG customers for the energy that these customers inject onto the distribution grid. As a result, APS overestimates the net cost to serve DG customers. This results in an understatement of the value credits for solar DG.

Second, even though TASC and others did not have adequate time to vet all of the assumptions used in the APS cost of service modeling, it appears that there are alternative assumptions that are justified for allocation of costs for distribution substation and primary distribution costs.

Based on TASC's review of feeder loading, it appears that usage of these facilities is greatest at time-of-peak demand, even though APS uses noncoincident peak to allocate costs. By adopting these assumptions, APS overallocates distribution costs to solar DG customers.

To show how alternative assumptions regarding allocation of costs would change the cost of service -- the cost of serving solar DG customers, I use an alternative approach to allocating costs based on the work done by TASC witness Mr. Beach in his opening testimony.

While TASC is not recommending that the Commission adopt cost of service assumptions in this docket, my testimony shows the types of issues that could be raised if parties had adequate time and access to models to test these cost of service models in a forum where there was adequate time to obtain access to a working cost of service model and to test the modeling assumptions.

Based on my conservative assumptions that I use as well as the allocators developed by Mr. Beach, I developed estimates of the percentage of costs covered by solar customers. These are 10 to 16 percentage points higher than estimated by APS.

Q. Great. Thank you, Mr. Monsen.

MR. RICH: I will tender Mr. Monsen for cross-examination.

ACALJ JIBILIAN: Okay. This is a time to take a break. We'll be back in 15 minutes and we can start the cross-examination.

(Recessed from 3:13 p.m. to 3:27 p.m.)

ACALJ JIBILIAN: Let's go back on the record.

Mr. Hogan, does Vote Solar have questions for this witness?

MR. HOGAN: No, Your Honor.

ACALJ JIBILIAN: Ms. Grabel?

MS. GRABEL: Yes, Your Honor.

CROSS-EXAMINATION

BY MS. GRABEL:

Q. Good afternoon, Mr. Monsen.

A. Good afternoon.

Q. I would like to take a look at your resume, if you would. It's attached to your testimony as WAM-1, I believe. You started your career, did you not, at the Madison Solar Energy Laboratory, correct?

A. Yes, I was on the academic staff there.

Q. It says that you developed simplified methods to analyze efficiency of passive solar energy systems, correct?

A. Yes.

Q. From there you spent eight years during the '80s at Pacific Gas & Electric Company where it looks like you worked as an economist in the Long-Term Planning Department working with DSM programming; is that correct?

A. I worked in various departments at Pacific Gas & Electric. I started in the Energy Conservation and Services Department. I was there for about two years. I was in the Rate Department for about two years. I was in the Economics and Forecasting Department for about two years, and then was in the Corporate Planning Department for about two years.

Q. When you were in the Rate Department, what was your role?

A. I worked on forecasting impacts of demand-side management resources, and also developing methods to compare demand-side management resources and supply-side resources.

Q. At Pacific Gas & Electric, you were never charged with putting together a cost of service study; is that correct?

A. That's correct.

Q. You were never charged with designing rates for utilities' residential customers; is that correct?

A. That's correct.

Q. And from Pacific Gas & Electric Company -- by the way, did you describe all of your roles at Pacific Gas & Electric Company?

A. Those were the four departments that I worked in. I worked on a lot of different things when I was there.

Q. From Pacific Gas & Electric Company, you went to MRW & Associates where you have been since 1989; is that correct?

A. Yes.

Q. And you indicate on your resume that you are a specialist in electric utility generation planning, resource auctions, demand-side management (DSM) policy, power market simulation, power project evaluation, and evaluation of customer energy cost control options; is that correct?

A. That's what my resume says, yes. I've also worked on a lot of other things as well as a consultant.

Q. In your 83 items of prepared testimony and exhibits that you have attached to this resume, where does it show your experience with cost of service studies?

A. Unfortunately, the names of the testimonies are not all that indicative of the types of issues that I worked on. They're not very descriptive, I guess. However, I've submitted testimony in several rate proceedings before the California Public Utilities Commission, and also before the Colorado Public Utilities Commission, looking at revenue allocation and rate design issues. I also did testimony in Nevada regarding the NV Energy cost of service studies in the proceeding late last year.

Q. In any of the engagements that you just mentioned, were you charged with developing a cost of service model yourself?

A. No. Typically, the way that we work on rate proceedings is that we receive the models that the utility provides, develops, and then that way everybody starts at the same place. And then that way you end up talking about changes of assumptions to the cost of service models as opposed to arguing about whether my model is correct and your model is incorrect. I've been involved in proceedings where things just completely get bogged down when you've got two competing models.

And so that's why in this proceeding, I thought it made sense to try to rely on the cost of service study that, the cost of service model that APS produced, and I was going to take that and use that for my analysis.

Q. Can I take it from your testimony that you have never developed a cost of service model?

A. No.

Q. No, I cannot take that from your testimony, or no, you have never developed a cost of service --

A. No, I've never developed my own cost of service model.

Q. Thank you. And at MRW, I've noticed you personally worked for Vote Solar before. That's a firm client, correct?

A. Yes.

Q. TASC is also a firm client, correct?

A. Yes.

Q. What other solar companies does your firm do work for?

A. Well, we've done work for a couple of companies on the wholesale side. So we've done work for NRG. We've done work for Luz. And we've also, on the retail side we've done work for Solar City.

Q. Have you done work for any other solar advocacy groups besides Vote Solar and TASC?

A. No.

Q. I know you previously worked with Ms. Kobor who is Vote Solar's witness in this case, correct?

A. Yes.

Q. Did you work closely with Ms. Kobor?
A. She was a senior associate at MRW.
Q. Did she ever work directly for you?
A. Yes, she would work with me in proceedings.
Q. Did you and Ms. Kobor coordinate your testimony in this proceeding?
A. No.
Q. Did you discuss your testimony in this proceeding?
A. No.
Q. Of the 83 items of prepared testimony and expert reports you have attached to your resume, 66 of them are related to proceedings in California; is that correct?
A. Subject to check, yes.
Q. Would you say the majority of the work that you do at MRW & Associates focuses on California energy policy?
A. The majority of the work I do focuses on California energy issues. We do work for, as I indicated, wholesale generators, retail suppliers. We do work for large customers. For example, the city of San Diego was the first client I had when I came to MRW in 1989, and I'm still doing work for them. But the California Commission keeps us very busy.
Q. Thank you. I would like you to turn to page 3

of your rebuttal testimony. I'm specifically looking at lines 1 through 4. You state, and you've actually said this a couple of times on the stand this afternoon, "This is a proceeding that is primarily concerned with the value and cost of DG. It is not a rate-setting proceeding. Thus, this proceeding is not the appropriate place to consider cost of service issues for specific utilities or to consider new rate proposals."

Did I read that correctly?

A. Yes.

Q. I would like to read to you from the February 16, 2016, procedural order entered by Judge Jibilian in this case, which I read to Ms. Kobor yesterday, you might remember. Specifically, beginning on line 14.5, Her Honor wrote, "On October 20, 2015, at its regularly scheduled Open Meeting in the course of considering Docket No. E-01345A-13-0248, the Commission ordered that an evidentiary hearing be held in this generic docket to include, in addition to the value and cost of DG, cost of service issues related to Arizona Public Service Company's provision of service to DG and nonDG customers."

Do you continue to assert, in light of the Commission's order, that the proceeding is not the appropriate place to consider APS's cost of service issues?

A. I think my recommendation is that this is a proceeding related to the value and the cost of DG, and that, as I indicated on page 3 of my rebuttal testimony, it's not a rate-setting proceeding. It's an expedited proceeding relative to a proceeding where you might normally consider cost of service issues, such as a general rate case.

Q. Would you agree that it is appropriate for APS to have submitted its cost of service study in response to the Commission's order?

A. I don't disagree that they submitted a cost of service study. I don't think it's inappropriate that they submit a cost of service study. I don't believe that a cost of service study is the appropriate tool for valuing solar.

Q. You agree, I believe, that APS uses long-term analyses as part of its resource planning process, correct?

A. Yes.

Q. That does not mean that APS recovers through current rates the long-term value of any specific resource; is that correct?

A. In any particular year, it doesn't. But over time, it would.

Q. You believe that APS recovers through current rates the long-term value assessed at any specific time during its integrated resource planning process?

A. No. But over time, APS would recover the long-term value associated with those resources in different years; but in a particular year, it doesn't recover the full value of those resources.

Q. Mr. Monsen, do you understand that when APS acquires a resource, that investment is put into the company's rate base, and it earns a return based on that plant investment, and it is the investment price of that asset that is depreciated over time, and that's how APS collects its return?

A. Yes, I understand that.

Q. And you understand that that does not correlate necessarily to any value assigned to it during the IRP process; is that correct?

A. That's correct.

Q. Is there any reason to distinguish a distributed generation resource from every other resource in the utility's generation portfolio?

A. Well, a distributed generation resource is not owned by the utility, and so that's a difference relative to utility-owned assets upon which the utility earns an authorized or has the opportunity to earn an authorized rate of return.

Q. Is there any reason to distinguish how a DG resource is compensated from any other resource in a utility's portfolio?

A. I don't think I understand your question. Could you repeat it, please?

Q. Is there any reason to distinguish how a DG resource owner is compensated compared to how APS would be compensated for the respective resources that they own?

A. Well, that happens all the time, I believe, with regard to, say, power purchase agreements that APS enters into. APS doesn't earn a rate of return on those power purchase agreements, which is different than the way it earns a rate of return on its own resources. So it's not surprising that there would be different ways that those resources would be compensated.

Q. Your testimony is that distributed generation is a resource for APS; is that correct?

A. Yes, it provides energy to APS at the point of interconnection between the customer and the APS distribution system.

Q. And your testimony is that because it is a resource for APS, we should assess it the same way that we assess all other of APS's resources in APS's portfolio; is that correct?

A. Could you define what you mean by "assess"? Are you talking about long-term or short-term assessment?

Q. Long-term.

A. It would not be -- I think it's actually very reasonable to assess, as Mr. Beach indicated, the long-term value and benefits and costs of distributed generation in the same way that APS evaluates, say, energy efficiency and demand response resources, and the way that it likely evaluates the cost effectiveness of generating resources.

Q. I would like you to turn to page 29 of your rebuttal testimony. Are you there?

A. Yes.

Q. Page 29 of your rebuttal testimony discusses your recommended use of the peak capacity allocation factors, or otherwise known as PCAFs; is that what you would refer to those as?

A. Yes.

Q. Can you cite to any Arizona Corporation Commission case that uses PCAFs as part of cost of service ratemaking?

A. No.

Q. You do cite in your testimony to Pacific Gas & Electric; is that correct?

A. Yes.
Q. And Pacific Gas & Electric Company serves northern California; is that right?
A. Northern and central California, yes.
Q. Would you agree that northern and central California have a different climate than the vast majority of APS's service territory?
A. Yes.
Q. Would you agree that Pacific Gas & Electric's air conditioning load wouldn't be the same as APS's air conditioning load, for example?
A. For certain parts of the PG&E system, probably Arizona is hotter than, say, the southern central valley that PG&E serves, and so there could potentially be, you know, more air conditioning in Arizona, in the APS service territory than PG&E, yes.
Q. Would you agree that the PG&E system peak and load shape differs from that of APS?
A. Yes.
Q. Would you also agree that different system and load characteristics can justify the use of different cost allocators from one utility to another?
A. I could see using, potentially using different cost allocators, depending on, say -- yes, that's correct.

Q. Thank you. On page 29 you describe PG&E's approach to determine cost responsibility using the PCAF, and then you state on page 30, line 1, "This approach has been approved by the California Public Utilities Commission."

Do you suggest in that portion of your testimony that the Arizona Corporation Commission should deviate from the way it historically uses cost allocation and adopt the PCAF approach because that approach has been adopted by the California Commission?

A. Adopt the use of the PCAF approach in what context?

Q. Cost of service ratemaking.

A. This is not a cost of service proceeding, so I'm not making that recommendation. However, in a general rate case, such a recommendation might be made.

MS. GRABEL: I have no further questions. Thank you.

ACALJ JIBILIAN: Mr. Heyman?

CROSS-EXAMINATION

BY MR. HEYMAN:

Q. Good afternoon, Mr. Monsen.

A. Good afternoon.

Q. I have to tell you that when your testimony said that APS had met its burden and that its approach was reasonable, I didn't have any questions. But the insertion of the word "not" there did lead me to pull out my questions. So I just have a few questions for you.

A. Okay.

Q. As I understand what you did in your rebuttal testimony is you took APS's cost of service study methodology and you made adjustments as you felt were appropriate; is that correct?

A. That's not quite right. I tried to use APS's cost of service model, but was unable to do so because the model that I received was not a working model; and so what I ultimately did is I made adjustments to the value credits that Mr. Snook developed. And then the other thing that I did was, since again I couldn't use your model to calculate cost of service for generation distribution, primary distribution substations, I used a simplified approach for allocating costs using the PCAF approach that Mr. Beach developed.

Q. My question really didn't go to the model as much as to the methodology. So let me ask you another question that kind of gets to the same point.

If the Commission were to say, Mr. Monsen, we are accepting your testimony, we're accepting your recommendation, and we're going to implement that in the next rate case. It would basically be the APS methodology using its model as you modified it with your adjustments. Wouldn't that be correct?

A. I don't think I've made a recommendation in this proceeding to adopt a cost of service methodology.

Q. Well, but you did --

A. So I don't know why the Commission would adopt something that I'm not recommending.

Q. When you filed your testimony, you did file it as an advocate; isn't that correct? Because it's rebuttal testimony. You didn't file any direct testimony.

A. I did not file direct testimony, that's correct.

Q. Right. And in your testimony, as a matter of fact, you state at page 2, lines 9 through 11, that your testimony reviews APS's testimony related to the cost of service studies for net energy metered customers in the residential customer class; isn't that correct?

A. I reviewed APS's testimony, yes, that's correct.

Q. And then you also put forth some conclusions that you've reached in your testimony, correct?

A. Yes, I put forth conclusions.

Q. And I'm assuming that the reason you put the conclusions there is because you wanted the Commission to accept them?

A. Yes, and my recommendations were to specifically not make decisions or to make findings or conclusions in this docket regarding cost of service modeling because this is the inappropriate place. There's not enough time for parties to really dig in and understand --

Q. That's helpful. So when you spend 20-something pages of your testimony analyzing, presenting your analysis of the APS model, the APS cost of service methodology, you aren't saying, "Here is my analysis, but, Commission, don't accept my conclusions"?

A. No, I'm saying the Commission should accept my conclusions, which is this is not the appropriate place to adopt assumptions and methodologies for cost of service studies. That's one of my conclusions.

Q. And so you're not proposing a substitute methodology that the Commission should accept in this proceeding?

A. No, I'm proposing -- yes, that's correct. I'm not proposing an alternate methodology. I'm proposing that the Commission wait until a more appropriate venue and docket where parties actually have a chance to look at and understand the models that they've been provided in response to discovery.

Q. Perfect. So I just want to make sure I'm understanding you properly. The testimony that you have that talks about the adjustments that you make, the assumptions that you made, the criticisms you have of what APS presented in this Commission, drives to the point of "Commission, don't do anything with regard to cost of service in this case"?

A. And, in addition to that, my section 3 of my testimony --

Q. But does "and" mean yes? Yes, and?

A. Yes, and.

Q. Okay.

A. Yes, and. Section 3 of my testimony indicates that a cost of service study is not the appropriate tool for determining the value of solar. So a cost of service study might present, might be a data point, but it certainly shouldn't be the determinative factor in deciding the value of solar, because that's inconsistent with the way that other long-term resources are valued.

Q. This Commission has never rejected an APS cost of service study because it did not properly evaluate new generation resources; is that correct?

A. Could you say that again, please?

Q. Yeah, this Commission has never rejected a cost of service study analysis that APS has presented to it because it did not properly evaluate new generation sources; is that correct?

A. I don't know.

Q. Okay. Well, at page 3 of your testimony, let's go there for a second. Lines 15 through 17, you make an interesting statement based upon what you've just said is a lack of knowledge.

Let me just read to you what you're saying here on page 3. "Since a COSS focuses on short-term cost issues, it is not the proper tool for evaluating new generation resources, whether they are traditional utility scale projects or DG."

Now, when you said that, you're not aware of any instance in which the Commission may have already taken action on this and contradicted what you said or agreed with what you said?

A. I am unaware of the Commission ever approving a long-term generation resource based solely on a cost of service study.

Q. The fact that you are testifying on behalf of TASC, I'm going to presume -- and correct me if I'm wrong -- means that TASC has adopted your testimony as their position in this case. Do you know that to be true?

A. I believe so, yes.

Q. Has anybody told you to the contrary?

A. Not that I've heard.

Q. Okay. Let's turn then to page 9 of your testimony, lines 14 and 15, where you say, "There is no question that NEM customers do not have delivered load shapes that mimic those of the average residential customer."

I assume that after all this has gone on in today's testimony, the hearings that we've had today, that's still your testimony and that's still TASC's position?

A. Yes.

Q. Okay. What I would like to do is turn to page 33 and 34 of your rebuttal testimony, please. Starting with the question and answer on line 12, the question asks, "Have you estimated the impact of using the revised credits, and the 4.99 percent ROR on the net cost to serve NEM customers relative to collected revenue?"

And your answer is, "Yes, I have estimated the impacts on the portion of their cost to serve that the NEM customers on energy rates pay in a couple of different ways. Assuming a retail ROR of 8.07 percent as APS has done, which as mentioned above, is misrepresentative of the real world situation, but using TASC's recommended credits, NEM customers on energy rates pay 46 percent of their cost of service, as opposed to 36 percent as APS has stated. However" -- and this is the part I want to focus on -- "if I correct APS's revenue requirement to reflect its targeted 4.99 percent rate of return and then continue to use APS's credits, NEM customers on energy rates pay 42 percent of the cost to serve them. Using the same 4.99 percent ROR assumption and using TASC's recommended credits results in an increase to 58 percent."

That's still your testimony?

A. Yes, for a single year, that is my testimony.

Q. And so after all -- you're the last TASC witness. You're the last witness in this proceeding, it appears, unless we have some other witnesses come to kind of sponsor some documents. After the several years that the solar industry has requested a value of solar proceeding, after all the tens of thousands of pages of documents, after all the witnesses and the hours of cross-examination, the best case that the value of solar testimony has come up with from TASC is that 42 percent of the cost to serve a NEM customer is not paid by a NEM customer?

MR. RICH: Your Honor, I'm going to object to the form of the question in that it assumed a lot of things that are not in evidence at this point.

MR. HEYMAN: The 10,000 pages of discovery or the hours -- I'm just asking from the standpoint --

MR. RICH: It was more of a history lesson than a question. I'm happy to have you ask a question like that, but you're testifying in that question.

MR. HEYMAN: Well, that wouldn't be a first in the Commission.

ACALJ JIBILIAN: Could you ask the question in a little bit shorter way?

MR. HEYMAN: Yes.

BY MR. HEYMAN:

Q. Your best testimony in this proceeding is that, based upon your analysis as you've presented it to us, NEM customers pay 42 percent of the cost to serve them?

A. My testimony says a number of things related to your question. First, as I indicated, I was not able to do an analysis of the cost of service for NEM customers based on delivered load as I had hoped to do because I was unable after much wrestling to try to get the APS working model to actually calculate cost of service with changed assumptions. That would have been my preference, is to use that.

So instead of doing that, I fell back to the approach that APS's witness Mr. Snook used, which is let's use gross solar customer load in the cost of service study, and then develop some credits. Okay?

But that isn't really even the most important point. The most important point is that this is a one-year snapshot based on a retrospective view of the cost to serve APS's customers. It is not consistent with any sort of resource planning that I've ever been involved with. It's not consistent with any sort of evaluation of long-term resources.

What this says is that if everything stays the same today at this moment in time, using this method that I hadn't really proposed to use, I can get to about 42 percent. But again, that's not the value of solar, because the value of solar is a long-term resource that has a long-term set of costs and benefits that change over time. Therefore, to characterize my testimony as saying that 42 percent is the value of solar is completely incorrect.

Q. And thank you for that answer. I think you're correcting a statement that was never made. So let me just ask you your question.

Have you estimated the impact of using the revised credits and a 4.99 percent ROR on the net cost to serve NEM customers relative to collected revenue? That has nothing to do with value. Could you just answer that question?

A. For one year, yes.
Q. And the number is?
A. 42 percent, based on those assumptions.
Q. So if the Commission were to say, Mr. Monsen, you win. We're going to take your testimony and we're going to accept it, and we're going to find that today, for one year, the NEM customers are able to pay for 42 percent of the costs to serve them, you would be happy?
A. In the same way that if you were to look at the --
Q. Let me ask you the question this way.
A. Okay, yes, could you please.
Q. That was your testimony when you filed it on April 7 of this year, what we read from pages 33 and 34?
A. Yes.
Q. And that's your testimony today?
A. Yes.
MR. HEYMAN: Okay. I have no further questions. Thank you.
ACALJ JIBILIAN: Mr. Pozefsky?
MR. POZEFSKY: I have no questions, Your Honor.
ACALJ JIBILIAN: Ms. Scott?
MS. SCOTT: I have just a few.

CROSS-EXAMINATION

BY MS. SCOTT:

Q. Good afternoon, Mr. Monsen.

A. Good afternoon.

Q. The way I interpret your testimony, you're saying that a cost of service study is a short-term analysis of APS's costs, such as the analysis that's performed in a rate case, correct?

A. That's correct.

Q. Okay. And you're also saying that you don't believe that such an analysis is appropriate to determine the value of solar?

A. In the same way as this Commission uses long-term cost/benefit analyses to determine the value of other demand-side resources and does not use a cost of service study in that assessment, that's what I'm saying, yes.

Q. Okay. So would you agree with me then, as a lot of other parties to this proceeding, that the avoided cost methodology would be one appropriate way to value solar?

A. Yes.

Q. And you're suggesting that it should be a long-term avoided cost determination; is that correct?

A. That seems reasonable to me, but the focus of my

testimony is really on the cost of service issues.
Q. Okay. Did you review the testimony of APS witness Brad Albert?
A. He wasn't really dealing with cost of service issues. I think I looked at it, but not in any depth.
Q. His was more on value of solar methodologies.
A. That's right.
Q. Okay. I have one other question. Do you believe that cost of service study is appropriate, however, to determine the cost shift?
A. A cost of service study can determine the potential revenue and costs of service in a particular year; and so if you're worrying about a potential cost shift in a one-year period, then yes, you could say that. However, as Mr. Beach discussed, if a resource has long-run benefits greater than long-run costs, then there's not a cost shift overall. But for a one-year period, a cost of service study could answer that question. That's why I said it's a data point, but it's only a data point for a particular year.
Q. Okay. And I just want to make sure I understand your position. So that if the cost of service study, let's say -- and I'm going to use a hypothetical here. APS used a cost of service study, its cost of service study as it would in a rate case, and it determined that

for that historical test year, let's say there was a $50 cost shift to nonparticipating customers.

Is that an appropriate evaluation, or are you saying, on the other hand, that it has to also consider the long-term benefits of solar?

A. It's appropriate -- the use of a cost of service study would be appropriate to look at the current-day cost to serve NEM customers and the potential short-run benefits associated with those customers. However, that would not give you a good estimate of the value of solar over the life of the investment.

Q. So you're saying that the number produced by the cost of service study has to be compared to the benefits produced in a value of solar study? Is that what you're saying?

A. No. I think what I'm saying is, if you were to look at the annual benefits and costs of a long-term value of solar study, looking at a cost of service study might be like looking at the first year of those benefits and costs. It might potentially be considered that.

Does that answer your question?

Q. I'm not sure. I'm not sure. I guess so. I guess it does.

Let me see. I think that --

MS. SCOTT: Your Honor, could I just look at his testimony once more?

ACALJ JIBILIAN: Sure.

(A brief pause.)

MS. SCOTT: That's all I have. Thank you, Mr. Monsen.

THE WITNESS: You're welcome.

ACALJ JIBILIAN: Do you have redirect, Mr. Rich?

MR. RICH: I do not, Your Honor.

ACALJ JIBILIAN: Thank you very much for your testimony, Mr. Monsen.

THE WITNESS: You're welcome.

ACALJ JIBILIAN: You're excused.

I think we already discussed all our procedural issues. Are there any more?

Yes, Mr. Loquvam.

MR. LOQUVAM: No issue. Only to note the protective order filing has been made. It's in the docket and waiting.

ACALJ JIBILIAN: And I will issue a procedural order on that very quickly.

We will be back in this room on June 8 at 9:30 a.m. Thank you very much. I'll see you then.

(The hearing recessed at 4:10 p.m.)

INDEX TO EXAMINATIONS

INDEX TO EXHIBITS

NO.	DESCRIPTION	IDENTIFIED	ADMITTED
AIC-10	Home Solar System Questions	1869	1976
AIC-11	Demeter Power Current Markets Map	1871	1976
AIC-12	Sunrun Inc.'s Form 10-K	1872	1976
AIC-13	SEIA Fact Sheet	1874	1976
AIC-14	SolarCity Subsidiaries	1875	1976
AIC-15	Sunrun 2015 Q4 Review	1885	1976
AIC-16	PV Safety and Firefighting Article	1900	1976
AIC-17	Report by The Fire Protection Research Foundation	1904	1976
APS-14	Article from Fortune Magazine	1916	1975
APS-15	MIT Study Excerpt	1926	1975
APS-16	Table 1 from IRP	--	1975

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Colette E. Ross

COLETTE E. ROSS
Certified Reporter
Certificate No. 50658

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Gary W. Hill

GARY W. HILL
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